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SECTION 10

POWER SYSTEM COMPONENTS

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10.1 TRANSFORMERS

10.1.1 Transformer Theory

Elementary theory is developed from the viewpoint of a 3-phase three-leg concentric-cylindrical two-winding transformer, with the primary low-voltage winding next to the core and the secondary high-voltage winding outside the primary winding. This corresponds to a generator-step-up transformer of moderate kVA. Most of the information is also applicable to single-phase transformers with windings on two legs, 3-phase transformers with five-leg cores, transformers with the primary winding outside the secondary winding, three-winding transformers, substation transformers, etc.

Sinusoidal voltage is induced in windings by sinusoidal variation of flux

$$E = 4.44 \times 10^{-8} a_c B f N \quad (10-1)$$

where a_c = square inches cross section of core, B = lines per square inch peak flux density, E = rms volts, f = frequency in hertz, and N = number of turns in winding.

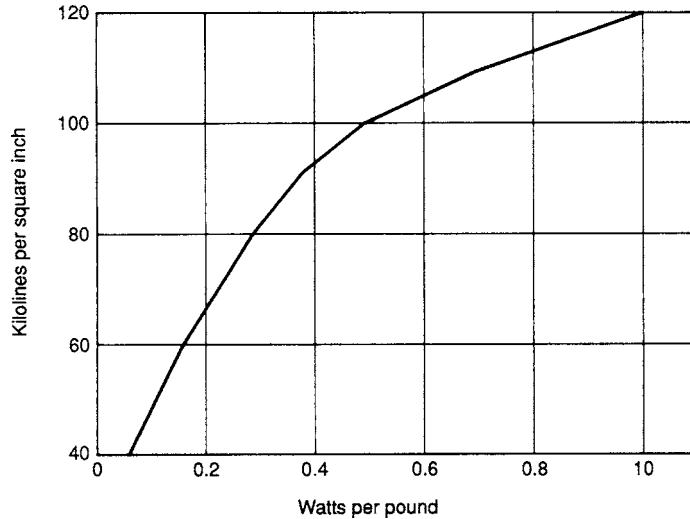


FIGURE 10-1 Typical core-loss curve for transformer core steel at 60 Hz.

The induced voltage in the primary (excited) winding approximately balances the applied voltage. The induced voltage in the secondary (loaded) winding approximately supplies the terminal voltage for the load.

Voltage ratio is the ratio of number of turns (“turn ratio”) in the respective windings. The rated open-circuit (no-load) terminal voltages are proportional to the turns in the windings, but under load the primary voltage usually must be somewhat higher than the rated value if rated secondary voltage is to be maintained, because of regulation effects.

Characteristics on Open Circuit. The core loss (no-load loss) of a power transformer may be obtained from an empirical design curve of watts per pound of core steel (Fig. 10-1). Such curves are established by plotting data obtained from transformers of similar construction. The basic loss level is determined by the grade of core steel used and is further influenced by the number and type of joints employed in construction of the core. Figure 10-1 applies for 9-mil-thick M-3-grade steel in a single-phase core with 45° mitered joints. Loss for the same grade of steel in a 3-phase core would usually be 5% to 10% higher.

Exciting current for a power transformer may be established from a similar empirical curve of exciting volt-amperes per pound of core steel as given in Fig. 10-2. The steel grade and core construction are the same as for Fig. 10-1. The exciting current characteristic is influenced primarily by the number, type, and quality of the core joints, and only secondarily by the grade of steel. Because of the more complex joints in the 3-phase core, the exciting volt-amperes will be approximately 50% higher than for the single-phase core.

The exciting current of a transformer contains many harmonic components because of the greatly varying permeability of the steel. For most purposes, it is satisfactory to neglect the harmonics and assume a sinusoidal exciting current of the same effective value. This current may be regarded as composed of a core-loss component in phase with the induced voltage (90° ahead of the flux) and a magnetizing component in phase with the flux, as shown in Fig. 10-3.

Sometimes it is necessary to consider the harmonics of exciting current to avoid inductive interference with communication circuits. The harmonic content of the exciting current increases as the peak flux density is increased. Performance can be predicted by comparison with test data from previous designs using similar core steel and similar construction.

The largest harmonic component of the exciting current is the third. Higher-order harmonics are progressively smaller. For balanced 3-phase transformer banks, the third harmonic components

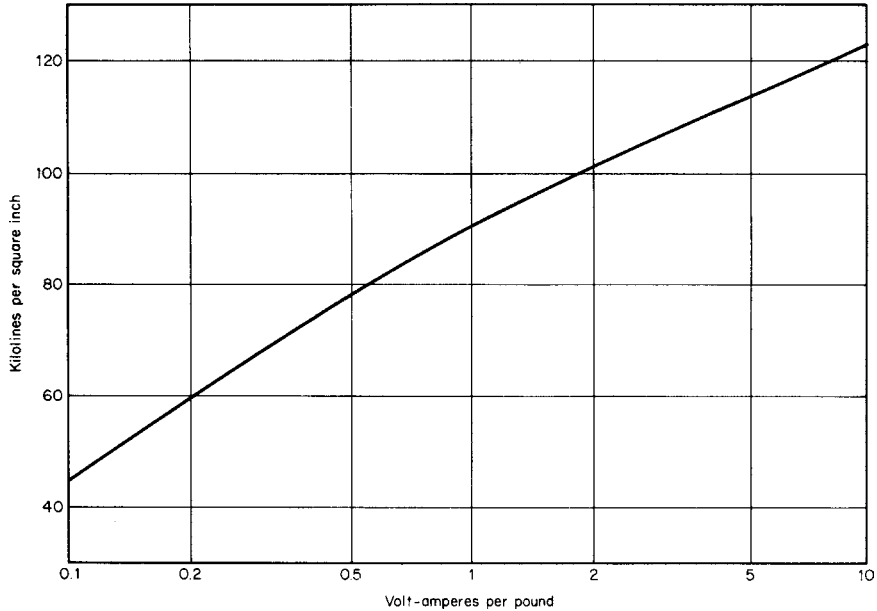


FIGURE 10-2 Typical exciting voltampere curve for transformer core steel at 60 Hz.

(or multiples of the third) are displaced by 120 fundamental degrees (deg) (or multiples of 120 fundamental deg) or 360 harmonic deg and therefore constitute a zero-phase-sequence system. Triple-harmonic currents may flow internally in delta-connected windings and externally in zero phase sequence paths in the connected system. The division of third-harmonic exciting current among available paths is not readily calculable.

Magnetizing Inrush Current. If an idle transformer is energized at a time in the voltage cycle when the flux in the core would normally be other than the actual residual flux in the core, the sinusoidal flux curve will be initially offset, and the offset decreases gradually with time [see Specht (1969) in References list at end of Sec. 10.1.3]. In extreme cases, the peak flux may be more than doubled, exceeding saturation of the core, and causing peak magnetizing current several times rated load current. Magnetizing inrush current is important, principally because of the possibility of false operation of transformer protective relays.

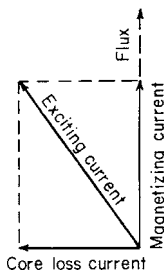


FIGURE 10-3 Phasor diagram of equivalent sinusoidal exciting current.

Characteristics on Short Circuit. If the primary winding of a transformer with 1:1 turn ratio is excited with the secondary winding short-circuited, a small exciting current flows in the primary winding, producing mutual flux mostly in the core. In addition, a short-circuit current flows forward in the primary and reverses in the secondary, causing leakage flux that passes between the two windings and completes its path through the core. The mutual and leakage flux together make net flux linkages with the secondary to induce voltage to supply the resistance drop in the secondary and make net flux linkages with the primary to induce a counter voltage equal to the applied voltage less the resistance drop in the primary. Figure 10-4 shows the space and phase relationships neglecting the exciting current. It is apparent that

$$E_p = I_p(R_p + R_s + jX) = I_p Z \quad (10-2)$$

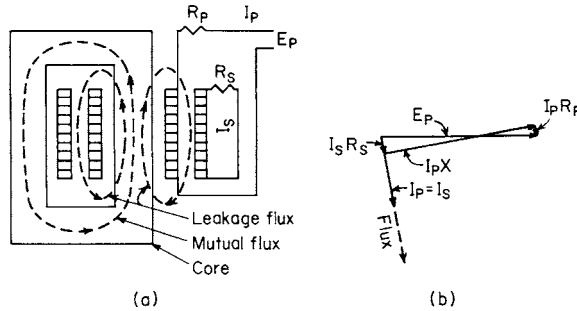


FIGURE 10-4 Short-circuited transformer: (a) flux distribution, single-phase; (b) phasor diagram, 1:1 ratio.

where E_p = rms volts applied to primary (phasor), I_p = rms amperes in primary (phasor), R_p = ohms resistance of primary winding, R_s = ohms resistance of secondary winding, X = ohms reactance (corresponding to the voltage induced in the primary by the leakage flux), and Z = ohms impedance ($R_p + R_s + jX$).

Resistance, Reactance, and Impedance. R_p and R_s are effective ac resistances. They are greater than the dc resistances as measured with direct current, because they include eddy loss in the conductor and stray loss in the core clamps, tank, etc. The reactance of the transformer is X , and the impedance is $Z = R_p + R_s + jX$.

Load Loss. The loss on short-circuit test at rated current is the load loss at rated kVA

$$L_L = I_R^2 R = I_R^2 Z_M \cos \theta \quad (10-3)$$

where I_R = rms amperes rated current, L_L = watts load loss at rated current, R = ohms ac resistance ($R_p + R_s$), Z_M = ohms impedance magnitude [$(R^2 + X^2)^{1/2}$], and θ = impedance angle of transformer.

The load loss at another current is

$$L = \frac{L_L I^2}{I_R^2} \quad (10-4)$$

where I = rms amperes and L = watts load loss.

Characteristics under Load. Exciting current in the primary winding produces mutual flux mostly in the core. Opposing currents in the primary and secondary windings cause leakage flux, which passes between the two windings and completes its path through the core. The magnitude and phase of the mutual flux depend on the voltage. The magnitude and phase of the leakage flux depend on the current. The mutual and leakage flux together generate in the primary a counter voltage equal to the applied voltage less the resistance drop in the primary, and generate in the secondary a voltage equal to the terminal voltage plus the resistance drop in the secondary.

For most purposes the effect of the leakage flux can be represented by the effect of series reactance in the secondary-winding circuit. Figure 10-5 shows the space relationships and the phase relationships in a transformer of 1:1 ratio. It is apparent that

$$E_p = E_s + I_s(R_s + jX) + I_p R_p \quad (10-5)$$

where E_p = rms volts at primary terminal (phasor), E_s = rms volts at secondary terminal (phasor), I_p = rms amperes in primary (phasor), I_s = rms amperes in secondary (phasor), R_p = ohms

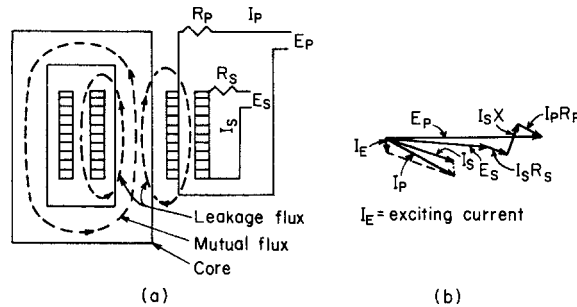


FIGURE 10-5 Loaded transformer: (a) flux distribution, single-phase; (b) phasor diagram, 1:1 ratio.

resistance of primary winding, R_s = ohms resistance of secondary winding, and X = ohms reactance of transformer.

Equivalent Circuits. Figure 10-6 shows a circuit which for most practical purposes is equivalent to the transformer of Fig. 10-5. The exciting current, I_E , is made up of two components, a magnetizing component flowing through X_M (the major component), and a loss component flowing through R_M . The values of R_M and X_M can be related to Figs. 10-1 and 10-2 if the core flux density at rated voltage is known. It will be found that these quantities vary with the voltage applied to the primary winding and they are usually determined for the rated voltage condition. For many purposes, the exciting current can be neglected and this leads to the simpler circuit of Fig. 10-7.

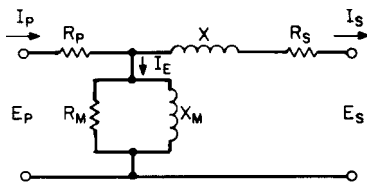


FIGURE 10-6 Equivalent circuit of a two-winding transformer considering exciting current.

Effect of Turn Ratio. Equation (10-5) and Fig. 10-7 represent a transformer of 1:1 turn ratio. A transformer of turn ratio T secondary to primary can be transformed into an

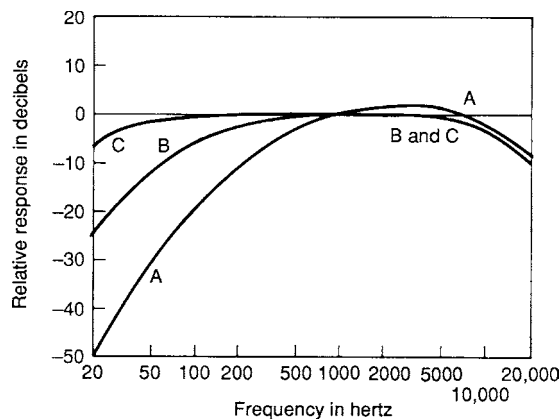


FIGURE 10-7 Equivalent circuit of a two-winding transformer neglecting exciting current.

equivalent 1:1 transformer by imagining the secondary winding replaced by a winding with the same number of turns as the primary winding, but using the same weight of conductor and occupying the same space as the secondary winding. I_s , E_s , and R_s in the real secondary winding become I_s/T , E_s/T , and R_s/T^2 . The impedance of the load, Z_L , becomes Z_L/T^2 . Thus, although Eqs. (10-2) to (10-5) and Figs. 10-4 to 10-7 were given for 1:1 turn ratio, they can be applied to any turn ratio. The fact that the simple series impedance of Fig. 10-7 may be used as equivalent to a transformer of any turn ratio is very helpful in the analysis of electric power systems. Secondary-winding characteristics corresponding to a fictitious secondary winding of 1:1 turn ratio are called secondary characteristics referred to the primary side. If more convenient, all characteristics can be referred to the secondary side by a reverse process.

Percent and Per Unit. Current, voltage, and kVA are frequently expressed as per unit or percent of rated value (25% = 0.25 per unit). The procedure is extended to resistance, reactance, and impedance by defining per unit impedance as (ohms impedance) $\times$ (rated current in amperes) $\div$ (rated voltage in volts). Quantities expressed in percent or per unit are the same regardless of whether they are referred to the primary side or the secondary side.

Regulation. It is apparent from Eq. (10-5) that if the load current and the secondary voltage are at rated value, the primary voltage must exceed rated value. The excess is called regulation. Regulation in per unit is defined as the difference between primary and secondary voltage divided by secondary voltage. For rated load at lagging power factor and rated secondary voltage, regulation is given exactly by Eq. (10-6) or approximately by Eq. (10-7).

$$G_r = [(R_r + P_r)^2 + (X_r + Q_r)^2]^{1/2} - 1 \quad (10-6)$$

$$G_0 = 100 \left[P_r R_r + Q_r X_r + \frac{(P_r X_r - Q_r R_r)^2}{2} \right] \quad (10-7)$$

where G_0 = percent regulation, G_r = per unit regulation, P_r = per unit load power factor, $Q_r = (1 - P_r^2)^{1/2}$, R_r = per unit resistance of transformer, and X_r = per unit reactance of transformer.

The calculation of regulation of a three-winding transformer is considerably more complex, depending on the load sharing between the two secondary windings. It will not be treated here.

Impedance Data. Resistance and reactance of transformers tend to follow normal patterns according to the ratings. Figure 10-8 shows resistance in percent (as determined by measurement of load loss on impedance test). Specific units may vary as much as $\pm 30\%$ depending largely on the evaluation of losses as compared with capital cost. Figure 10-9 shows ranges of reactance in percent. Special designs (transformers with all windings high-voltage, autotransformers, designs with

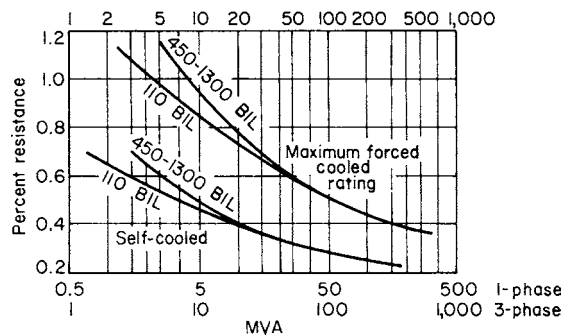


FIGURE 10-8 Resistance of typical power transformer.

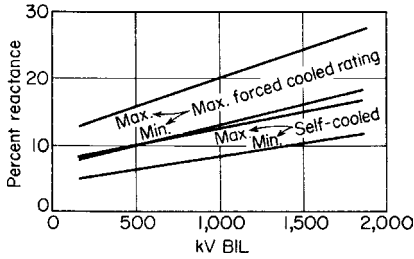


FIGURE 10-9 Reactance of typical power transformer.

overload ratings, etc.) may have reactances outside the limits shown.

Efficiency. This is given by

$$F_r = \frac{E_s I_s \cos \theta}{E_s I_s \cos \theta + L_{NS} + L_{LS}} \quad (10-8)$$

where E_s = rms volts at secondary terminals, F_r = per unit efficiency, I_s = rms amperes in secondary, L_{LS} = watts load loss at I_s , L_{NS} = watts no-load loss at $E_s(I_s = 0)$, and θ = impedance angle of load.

Three-Winding-Transformer Load Losses. The load losses of three-winding transformers, with all three windings carrying loads simultaneously, may be calculated from characteristics obtained by considering each pair of windings as a two-winding transformer.

$$L_T = \left(\frac{I_P}{I_A}\right)^2 \frac{L_{PS} + L_{PT} - L_{ST}}{2} + \left(\frac{I_S}{I_A}\right)^2 \frac{L_{ST} + L_{PS} - L_{PT}}{2} + \left(\frac{I_T}{I_A}\right)^2 \frac{L_{PT} + L_{ST} - L_{PS}}{2} \quad (10-9)$$

where I_A = rms amperes reference current referred to winding P ; I_P = rms amperes in winding P ; I_{SP} = rms amperes in winding S referred to winding P ; I_{TP} = rms amperes in winding T referred to winding P ; L_{PS} = watts load loss in windings P and S as a two-winding transformer at I_A ; L_{PT} , L_{ST} = similar; and L_T = watts total load loss.

The loss is usually computed at, or corrected to, a temperature of 75°C for 55°C average rise units and 85°C for 65°C average rise units.

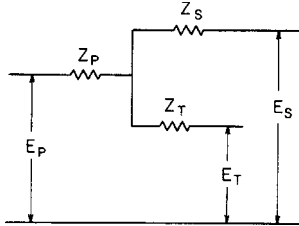


FIGURE 10-10 Equivalent circuit of a three-winding transformer.

Three-Winding-Transformer Equivalent Circuit. The equivalent circuit of a three-winding transformer may be determined from the three impedances obtained by considering each pair of windings separately. One form is shown in Fig. 10-10, in which

$$Z_P = \frac{Z_{PS} + Z_{PT} - Z_{ST}}{2} \quad (10-10)$$

$$Z_S = \frac{Z_{PS} + Z_{ST} - Z_{PT}}{2} \quad (10-11)$$

$$Z_T = \frac{Z_{PT} + Z_{ST} - Z_{PS}}{2} \quad (10-12)$$

where Z_P , Z_S , Z_T = ohms branch impedances in Fig. 10-10; Z_{PS} = ohms impedance from winding P to winding S in two-winding equivalent circuit of Fig. 10-7; and Z_{PT} , Z_{ST} = similar. All ohmic values of impedance must be referred to one common winding (i.e., the primary winding).

Four-Winding-Transformer Equivalent Circuit. The equivalent circuit of a four-winding transformer may be determined from the six impedances obtained by considering each pair of windings separately. One form is shown in Fig. 10-11, in which

$$Z_P = \frac{Z_{PQ} + Z_{PS} - Z_{SQ}}{2} - \frac{Z_A Z_B}{2(Z_A + Z_B)} \quad (10-13)$$

$$Z_S = \frac{Z_{PS} + Z_{ST} - Z_{PT}}{2} - \frac{Z_A Z_B}{2(Z_A + Z_B)} \quad (10-14)$$

$$Z_T = \frac{Z_{ST} + Z_{TQ} - Z_{SQ}}{2} - \frac{Z_A Z_B}{2(Z_A + Z_B)} \quad (10-15)$$

$$Z_Q = \frac{Z_{TQ} + Z_{PQ} - Z_{PT}}{2} - \frac{Z_A Z_B}{2(Z_A + Z_B)} \quad (10-16)$$

$$Z_A = (K_1 K_2)^{1/2} + K_1 \quad Z_B = (K_1 K_2)^{1/2} + K_2 \quad (10-17)$$

$$K_1 = Z_{PT} + Z_{SQ} - Z_{PS} - Z_{TQ} \quad K_2 = Z_{PT} + Z_{SQ} - Z_{PQ} - Z_{ST} \quad (10-18)$$

where Z_A = ohms branch impedance in Fig. 10-11 (complex); Z_B, Z_P, Z_S, Z_T, Z_Q = similar; Z_{PS} = ohms impedance (complex) from winding P to winding S in two-winding equivalent circuit of Fig. 10-7; and $Z_{PT}, Z_{PQ}, Z_{ST}, Z_{SQ}, Z_{TQ}$ = similar.

Phase-Interconnected Transformers. These transformers that is with windings from more than one phase on a single core leg can be represented by an equivalent circuit only if each winding on a leg is considered as if it were brought out to separate terminals [see Cogbill (1955) in list at end of Sec. 10.1.3].

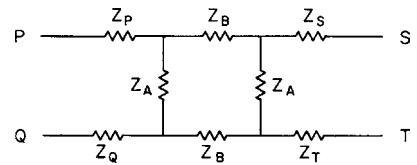


FIGURE 10-11 Equivalent circuit of a four-winding transformer.

10.1.2 Transformer Connections

Parallel Operation. Two single-phase transformers will operate in parallel if they are connected with the same polarity. Two 3-phase transformers will operate in parallel if they have the same winding arrangement (e.g. Y-delta), are connected with the same polarity, and have the same phase rotation. If two transformers (or two banks of transformers) have the same voltage ratings, the same turn ratios, the same impedances (in percent), and the same ratios of reactance to resistance, they will divide the load current in proportion to their kVa ratings, with no phase difference between the currents in the two transformers. If any of the above conditions are not met, the load current may not divide between the two transformers in proportion to their kVA ratings and there may be a phase difference between currents in the two transformers.

Two unlike transformers connected in parallel will supply current to a load as follows:

$$I_L = \frac{E_p}{\frac{1}{(T_1/Z_1) + (T_2/Z_2)} + Z_L \frac{(1/Z_1) + (1/Z_2)}{(T_1/Z_1) + (T_2/Z_2)}} \quad (10-19)$$

where E_p = rms volts on primary side (phasor), I_L = rms amperes total load current (phasor), T_1 = turn ratio secondary to primary of unit 1, T_2 = turn ratio secondary to primary of unit 2, Z_1 = ohms impedance of unit 1 referred to secondary side (complex), Z_2 = ohms impedance of unit 2 referred to secondary side (complex), and Z_L = ohms impedance of load (complex).

The magnitude of the current in unit 1 is

$$I_{r1} = \frac{\{[T_1 R_{r2} I_{rL} + (T_1 - T_2) E_{r1} \cos \theta]^2 + [T_1 X_{r2} I_{rL} + (T_1 - T_2) E_{r1} \sin \theta]^2\}^{1/2}}{[(T_1 R_{r2} + T_2 R_{r1})^2 + (T_1 X_{r2} + T_2 X_{r1})^2]^{1/2}} \quad (10-20)$$

where E_{r1} = rms voltage of secondary terminals in per unit of unit 1, I_{rL} = rms total load current in per unit of unit 1, I_{r1} = rms current in secondary of unit 1 in per unit of unit 1, T_1 = ratio secondary turns to primary turns in unit 1, T_2 = ratio secondary turns to primary turns in unit 2, R_{r1} = equivalent resistance of unit 1 in per unit of unit 1, R_{r2} = equivalent resistance of unit 2 in per unit of unit 1, X_{r1} = equivalent reactance of unit 1 in per unit of unit 1, X_{r2} = equivalent reactance of unit 2 in per unit of unit 1, and θ = impedance angle of load (lagging current positive).

NOTE: Per unit means percent divided by 100, that is, 10% = 0.1 per unit.

The current in the second unit may be determined by using Eq. (10-20) with designation of first and second transformers reversed.

Phase-interconnected transformers (i.e., with windings from more than one phase on a single core leg) offer special complication when unlike units are connected in parallel. [See Cogbill (1955) in list at end of Sec. 10.1.3.]

3-Phase to 3-Phase Transformations. The delta-delta, the delta-Y, and the Y-Y connections are the most generally used; they are illustrated in Fig. 10-12. The Y-delta and delta-delta connections may be used as step-up transformers for moderate voltages. The Y-delta has the advantage of providing a good grounding point on the Y-connected side which does not shift with unbalanced load and has the further

advantage of being free from third-harmonic voltages and currents; the delta-delta has the advantage of permitting operation in V in case of damage to one of the units. Delta connections are not the best for transmission at very high voltage; they may, however, be associated at some point with other connections that provide means for properly grounding the high-voltage system; but it is better, on the whole, to avoid mixed systems of connections. The delta-Y step-up and Y-delta step-down connections are without question the best for high-voltage transmission systems. They are economical in cost, and provide a stable neutral whereby the high-voltage system may be directly grounded or grounded through resistance of such value as to damp the system critically and prevent the possibility of oscillation.

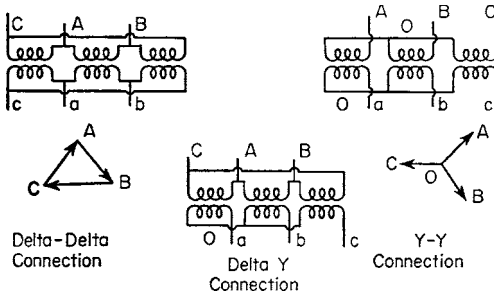


FIGURE 10-12 Standard 3-phase/3-phase transformer systems.

The Y-Y connection (or Y-connected autotransformer) may be used to interconnect two delta systems and provide suitable neutrals for grounding both of them. A Y-connected autotransformer may be used to interconnect two Y systems which already have neutral grounds, for reasons of economy. In either case, a delta-connected tertiary winding is frequently provided for one or more of the following purposes.

In *stabilization of the neutral*, if a Y-connected transformer (or autotransformer) with a delta-connected tertiary is connected to an ungrounded delta system (or poorly grounded Y system), stability of the system neutral is increased. That is, a single-phase short-circuit to ground on the transmission line will cause less drop in voltage on the short-circuited phase and less rise in voltage on the other two phases. A 3-phase three-leg Y-connected transformer without delta tertiary furnishes very little stabilization of the neutral, and the delta tertiary is generally needed. Other Y connections offer no stabilization of the neutral without a delta tertiary. With increased neutral stabilization, the fault current in the neutral on single-phase short circuit is increased, and this may be needed for improved relay protection of the system.

Third-harmonic components of exciting current find a relatively low impedance path in a delta tertiary on a Y-connected transformer, and less of the third-harmonic exciting current appears in the connected transmission lines, where it might cause interference with communication circuits. Failure to provide a path for third-harmonic current in Y-connected 3-phase shell-type transformers or banks

of single-phase transformers will result in excessive third-harmonic voltage from line to neutral. The bank of a 3-phase, three-legged core-type Y-connected transformer acts as a delta winding with high impedance to the other windings. As a consequence, there is very little third-harmonic line-to-neutral voltage and a separate delta tertiary is not needed to reduce it.

An external load can be supplied from a delta tertiary. This may include synchronous or static capacitors to improve system operating conditions.

Loading Y-Connected Transformers Line to Neutral. Load can be connected line to neutral only if (1) the source side of the transformer is delta-connected, or (2) the source side is Y-connected with the neutral connected back to the source neutral.

If one of these two conditions is not maintained, the neutral will shift, reducing the voltage of the loaded phase and increasing the voltage of the other phases.

The Open-Delta Connection, or V Connection. This is an unsymmetric connection which is used if one transformer of a bank of three single-phase delta-connected units must be cut out because of failure. It is a connection that is sometimes resorted to as an emergency expedient or used as a temporary measure with the intention of completing the delta when conditions of load warrant the addition of a third unit. If one phase of a 3-phase delta-connected transformer of the shell type should fail, operation may be continued at reduced capacity by short-circuiting the damaged phase; if of the core type, operation may be continued by leaving the damaged phase open-circuited, provided that the windings are still capable of withstanding the voltage stresses. Since full-line currents flow in the windings out of phase with the transformer voltages, the normal capacity of the open-delta bank is reduced to 57.7% of its delta rating.

The T Connection. This uses two transformers, the first called the “main” transformer, connected from line to line; and the second, called the “teaser” transformer, connected from the midpoint of the first to the third line. It requires that the midpoint of both primary and secondary windings be available for connections. It has an advantage over the V connection in being more nearly symmetrical if the proper taps have been provided. As in the case of the V connection, two transformers of a bank of delta-connected transformers, one of which has failed, may be connected in T, and if 10% taps can be used for the teaser transformer, the transformation will be more nearly symmetrical than if the V connection were used. Where T-connected transformers are installed, they may later be changed to delta with the addition of one more transformer and an increase in rating of the bank of 73%. In the T connection (Fig. 10-13) the transformer AD, known as the teaser transformer, may be a duplicate of the main transformer so as to be interchangeable with it, and it may or may not be provided with an 86.6% tap. Its rated capacity will then be 15.5% more than actually necessary. The main transformer operates at a power factor of 0.866, and therefore, if the two transformers are duplicates, their total rated capacity will be 15.5% greater than the capacity of the load in kVA, or each transformer must have a rating of 0.577 of the kVA delivered. If the transformers are not interchangeable, the teaser may be reduced to a rating of one-half the kVA delivered.

In connecting transformers in T, *care should be taken to keep the relative phase sequence of the windings the same*; otherwise the impedance of the main transformer may be excessively high and cause undue unbalance. Figure 10-13 illustrates the right and the wrong way.

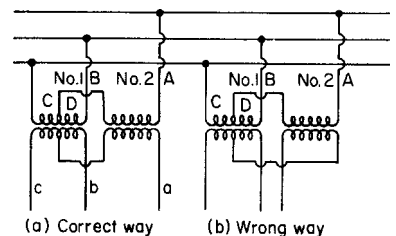


FIGURE 10-13 T-connected transformers.

3-Phase to 6-Phase Transformation. 6 Phases are commonly used for supply of rectifiers. Six phases can be obtained as shown in Fig. 10-14 (double delta) or as in Fig. 10-15 (double Y) respectively. It is not necessary in this transformation, when the neutral connection is required, to have two secondary windings; instead a middle tap may be brought out, all the middle taps being connected together to form the neutral.

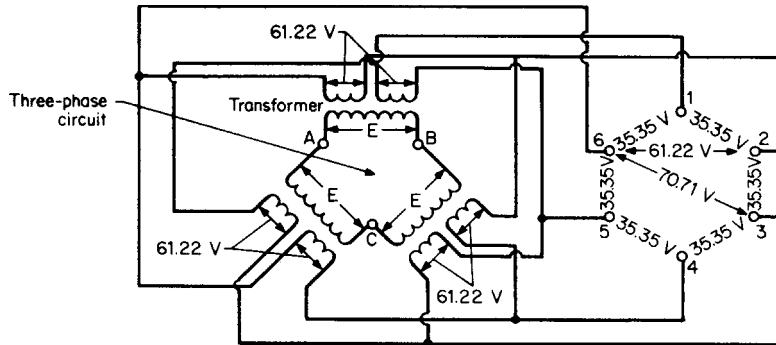


FIGURE 10-14 Three-phase/six-phase transformation, double delta.

The Interconnected Y Connection. This connection (see Fig. 10-16) is commonly referred to as the *zigzag* connection. It may be used with either a delta-connected winding as shown or a Y-connected winding for step-up or step-down operation. In either case, the zigzag winding produces the same angular displacement as a delta winding and, in addition, provides a neutral for grounding purposes. Owing to the angular relation of voltages of the zig and zag windings, the amount of conductor material required for such a connection is 15% greater than a corresponding Y or delta connection. If a transformer consists of zigzag and Y connections, a third winding, delta-connected, is usually necessary for reasons given under the Y-Y connection. If the delta-connected winding is included for purposes other than that of providing a third source of power, in some cases it is practical to design it for the same voltage as the zigzag winding and connect it in parallel with the zigzag winding to form the delta-grounded transformer connection [see Gross and Rao (1953) in list at end of Sec. 10.1.3].

The zigzag connection is used extensively for grounding transformers, the sole purpose of which is to establish a neutral point for grounding purposes; therefore no other windings are required.

10.1.3 Power Transformers

Power transformers may be defined as transformers used to transmit or distribute power in ratings larger than distribution transformers (usually over 500 kVA or over 67 kV). Some of the following information on power transformers is also applicable to other types of transformer.

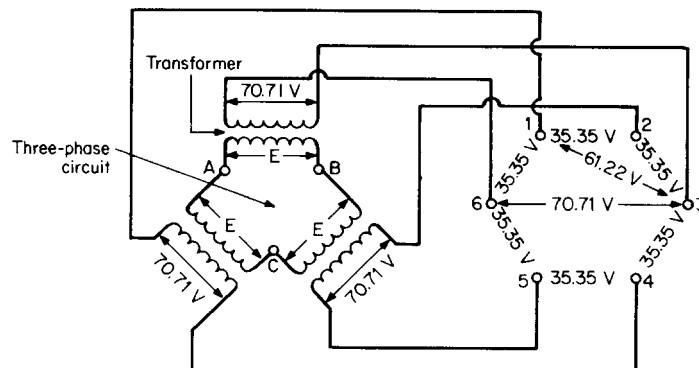


FIGURE 10-15 Three-phase/six-phase transformation, double Y.

The Rated Constants of a Power Transformer. The kVA, terminal voltages and currents are defined in ANSI C57.12.80. They are all based on the rated winding voltages at no load, although it is recognized that the actual primary voltage in service must be higher than the rated value by the amount of the regulation, if the transformer is to deliver rated voltage to the load on the secondary.

10.1.4 Design

The design of commercial transformers requires the selection of a simple yet suitable form of construction so that the coils are easy to wind and the core is easy to build. At the same time, the mean length of the windings and magnetic circuit must be as short as possible for a given cross-sectional area, so that the amount of material required and resulting losses are minimized. The core must provide a continuous path for magnetic flux while its lamination pattern must be easy to cut and stack. The windings should be insulated in a simple and economical manner, should permit the dissipation of heat (due to losses) by means of cooling ducts, and should be mechanically strong to withstand short-circuit forces.

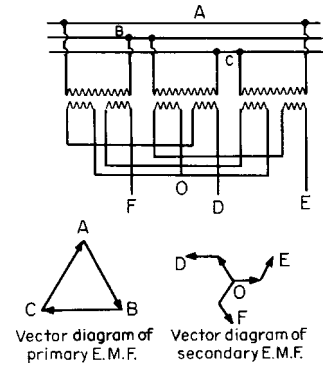


FIGURE 10-16 Interconnected Y connection.

Two Types of Transformer in Common Use. When the magnetic circuit takes the form of a single ring encircled by two or more groups of primary and secondary windings distributed around the periphery of the ring, the transformer is termed a *core-type transformer*. When the primary and secondary windings take the form of a common ring which is encircled by two or more rings of magnetic material distributed around its periphery, the transformer is termed a *shell-type transformer* (Fig. 10-17). Actually, core-type (or “core-form”) in U.S. power-transformer engineering usage means that the coils are cylindrical and concentric (the outer winding over the inner) whereas shell-type (or “form”) denotes large pancake coils that are stacked or interleaved to make primary-secondary (P-S) groups. Except for certain extremes of current rating, the choice between the core- and shell-type construction is largely a matter of manufacturing facilities and of individual preference.

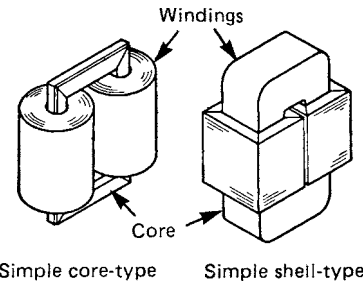


FIGURE 10-17 Forms of magnetic circuits for transformers.

Core-form transformer characteristic features are a long mean length of magnetic circuit and a short mean length of windings. Commonly used core constructions for single-phase and 3-phase units are shown in Figs. 10-18 and 10-19, respectively. The three-leg (one active leg) and four-leg (two active) construction of single-phase cores and the five-leg (three active) construction of 3-phase cores are used to reduce overall height. In these cases, the core encloses the cylindrical windings in

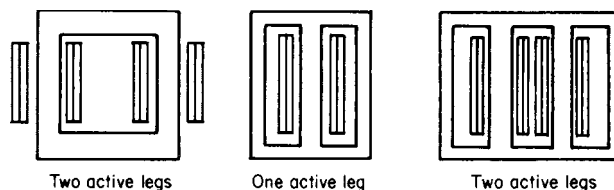


FIGURE 10-18 Single-phase core-form core construction.

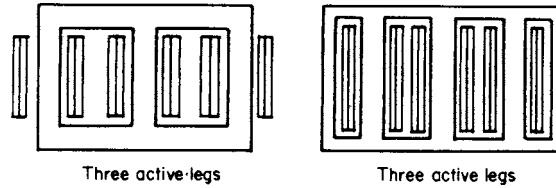


FIGURE 10-19 Three-phase core-form core construction.

a similar fashion to the shell-form construction. The simple concentric primary (inside) and secondary (outside) winding arrangement is common for all small- and medium-power transformers. However, large MVA transformers frequently have some degree of interleaving of windings, such as secondary-primary-secondary (S-P-S). The core-form construction can be used throughout the full size range of power transformers.

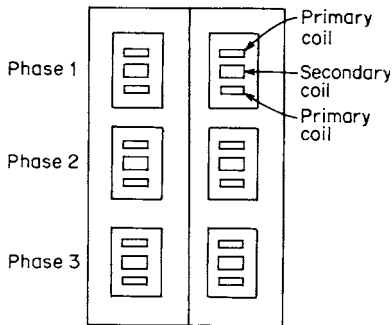


FIGURE 10-20 Conventional 3-phase core for the rectangular-pancake-interleaved-coil structure (shell type). The groups of pancake coils may be round or rectangular.

Shell-form transformer characteristic features are short mean length of magnetic circuit and long mean length of windings. This results in the shell-form transformer having a larger area of core and smaller number of winding turns than the core form of same output and performance. Also, the shell form would typically have a greater ratio by weight of steel to copper. Figure 10-20 shows the conventional 3-phase shell-form core with the coils in cross section. Primary-secondary-primary (P-S-P) coil grouping is most common, but P-S-P-S-P is often used.

Design Process. The design process begins with a customer specification. This contains the desired characteristics which allow the design engineer to make economical choices between different materials and construction geometrics. Some of these characteristics are voltage (kV), power rating (MVA), impedance (%), loss evaluation (\$/kW), temperature rating (°C), and cooling class (OA, FA, FOA). Some additional factors which

influence the transformer design are requirements for tertiary windings and no-load or load taps.

After the customer specification is understood, the design optimization can begin. Most power transformers are designed starting with a certain winding arrangement and dimensions of the core and coils. Initial characteristics of the transformer are calculated and then compared to the desired characteristics. The initial dimensions are then modified to better meet the desired characteristics. Repeating the process leads to close agreement of calculated characteristics with desired characteristics. The repeated calculations, converging on the optimum design, are usually performed by computer. Closeness of agreement of calculated characteristics with tested characteristics depends upon the degree of refinement of the design process, the closeness of agreement of the physical properties of the materials used (particularly the dielectric properties of the insulating materials and the magnetic properties of the core steel) with the properties assumed in the design calculation, and the accuracy of the manufacturing procedures and processes.

Refinement of the design process results from comparison with test data obtained on similar transformers. This applies particularly to core loss, stray loss, noise level, reactance, and dielectric strength. The following calculation methods are mostly approximate.

With an assumed core cross section and flux density, the *number of turns* in each winding is established from Eq. (10-1). The flux density is adjusted to give an integral number of turns in the low-voltage winding, and then an acceptable ratio of open-circuit terminal voltage results from an integral number of turns in the high-voltage winding.

Leakage flux density in the main gap (insulation space between windings) for a transformer with one core leg per phase, as shown in Fig. 10-21, is as follows:

$$B_L = \frac{4.52 I_R N}{h_E} \quad (10-21)$$

where B_L = lines per square inch peak leakage flux density, h_E = inches effective length of leakage flux path, I_R = rms amperes rated current of winding, and N = number of turns in winding.

If there is more than one leg per phase, Eq. (10-21) applies to the portion of winding on one leg. The effective length of leakage path is difficult to evaluate accurately. For concentric cylindrical windings, it is approximately

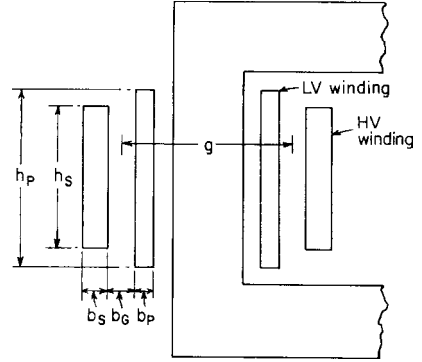


FIGURE 10-21 Dimensions of core-type concentric windings for reactance calculations.

$$h_E = \frac{h_P + h_S}{2} + 0.8 \left(\frac{b_P + b_S}{3} + b_G \right) \quad (10-22)$$

where b_G = inches radial distance between windings, b_P = inches radial width of winding P , b_S = inches radial width of winding S , h_P = inches length of winding P , and h_S = inches length of winding S .

Leakage reactance may be calculated for a transformer with one set of coils per phase as follows:

$$X_r = \frac{2.01 \times 10^{-7} a_L f I_R N^2}{E_R h_E} \quad (10-23)$$

where a_L = square inches effective cross section of leakage flux path, E_R = rms volts rated voltage of winding, f = frequency in hertz, h_E = effective length of leakage flux path in inches, I_R = rms amperes rated current of winding, N = number of turns in winding, and X_r = per unit reactance.

The effective cross section of the leakage flux path is difficult to evaluate accurately. For concentric cylindrical windings, it is approximately

$$a_L = \left(b_G + \frac{b_P + b_S}{3} \right) \pi g \quad (10-24)$$

where g = mean diameter of main gap, in.

Resistance loss in winding is

$$W_R = 2.57 M^2 \frac{234.5 + C}{309.5} \quad (10-25)$$

$$L_R = H_C W_R \quad (10-26)$$

where L_R = watts resistance loss in winding, M = rms kiloamperes per square inch current density, H_C = pounds weight of copper in winding, C = temperature in degrees Celsius, and W_R = watts per pound resistance loss in winding.

Eddy loss in the winding may be regarded as caused by circulating current induced in the strand by the magnetic flux passing through the strand. For a two-winding transformer,

$$W_E = 2.06 \times 10^{-10} d^2 f^2 B_L^2 \frac{309.5}{234.5 + C} \quad (10-27)$$

$$L_E = H_C W_E \quad (10-28)$$

where B_L = lines per square inch peak leakage flux density, from Eq. (10-21), C = Celsius temperature, d = inches thickness of strand perpendicular to flux, f = hertz frequency, L_E = watts eddy loss in winding, H_C = pounds weight of copper in winding, and W_E = watts per pound average eddy loss in winding.

Load loss is the sum of resistance and eddy losses in all windings plus stray loss. The stray loss is in itself an eddy loss produced by the leakage flux penetrating the surface of other conducting components, such as the core, core clamps, and tank. Historically, the stray loss has been predicted from test results on similar transformers, but finite element computer solutions have recently been developed to define the leakage flux paths accurately and permit more exact calculation of both stray and eddy losses.

No-load loss equals watts per pound determined from Fig. 10-1, multiplied by weight of the core multiplied by a correction factor depending on core configuration and processing and determined by experience.

General Design Characteristics. The relationship of power-transformer characteristics to scale factor can be illuminated by considering the effect of increasing all dimensions in the ratio S , while retaining the same thickness of core lamination and thickness of conductor strand, but imagining the conductor turns to be reconnected for a terminal voltage proportionate to the insulation thickness. Similarly the effect of increasing the flux density in the ratio B and the current density in the ratio M can be examined. The results are shown in Table 10-1.

Core dimensions are generally standardized in steps, with only a small number of dimensions varying to meet the requirement of the particular rating. Cold-rolled grain-oriented silicon steel strip in gages of 0.009 to 0.014 in is used with mitered corner joints to take advantage of the good characteristics of this material when carrying flux in the rolling direction.

10.1.5 Insulation

Insulation systems in power transformers consist of a fluid—either liquid or gas—together with solid materials. Petroleum-based oils have been used to insulate power transformers since 1886 and are still used in virtually all medium and large transformers (Sheppard 1986). Askeral was used from

TABLE 10-1 Scale Effects

Characteristic	At scale factor S	At flux density B^*	At current density M
Linear dimension	S		
Flux density	...	B	
Current density	...	...	M
Rated current	S^3	B	M
Rated voltage	S		
Rated kVA	S^4	B	M
Weight	S^3		
kVA/lb	S	B	M
Ω reactance	S^{-1}		
% reactance	S	B^{-1}	M
W core loss	S^3	B^2	
% core loss	S^{-1}	B	M^{-1}
W $I^2 R$ loss	S^2	...	M^2
% $I^2 R$ loss	S^{-1}	B^{-1}	M
W eddy loss	S^5	...	M^2
% eddy loss	S	B^{-1}	M
W stray loss†	S^4	...	M^2
% stray loss†	...	B^{-1}	M

*Applies only to the range in which core loss varies with the square of B .

†As a percent of rated current times rated volts.

1932 through the mid-1970s when the flammability of mineral oil was a concern, but it has since been completely phased out of transformer production because of environmental concerns. It has been replaced by any of a wide variety of high-flash-point fluids (silicones, high-flash-point hydrocarbons, chlorinated benzenes, or chlorofluorocarbons). Gas systems include nitrogen, air, and fluorogases. The fluorogases are used to avoid combustibility and limit secondary effects of internal failure. Some transformers have been constructed using low boiling-point liquids such as Freon which allows improved heat transfer using a 2-phase cooling system.

Within the core and coil assembly, insulation can be divided into two fundamental groups: major insulation and minor insulation. Major insulation separates the high- and low-voltage windings, and the windings to core. Minor insulation may be used between the parts of individual coils or windings depending on construction. Finally, turn insulation is applied to each strand of conductor and/or groups of strands forming a single turn.

Oil-Insulated Transformers. Low cost, high dielectric strength, excellent heat transfer characteristics, and ability to recover after dielectric overstress make mineral oil the most widely used transformer insulating material. The oil is reinforced with solid insulation in various ways. The major insulation usually includes barriers of wood-based paperboard (pressboard), the barriers usually alternating with oil spaces. Because the dielectric constant of the oil is 2.2 and that of the solid is approximately 4.0, the dielectric stress in the oil ends up being higher than that of the pressboard, and the design of the structure is usually limited by the stress in the oil.

The insulation on the conductors of the winding may be enamel or wrapped paper which is either wood- or nylon-based. The use of insulation directly on the conductor actually inhibits the formation of potentially harmful streamers in the oil, thereby increasing the strength of the structure (Nelson 1989). Again, the limit of dielectric strength is usually that of the oil.

Heavy paper wrapping is also usually used on the leads coming from the winding. In this case, the insulation serves to reduce the stress in the oil by moving the interface from the surface of the conductor (where the stress is high) to a distance away from the conductor (where the stress is considerably lower). Again, the stress in the oil determines the amount of paper required, and the thermal considerations establish the minimum size of the conductor for the necessary insulation.

Askeral-Insulated Transformers. These transformers have constructions similar to the oil-insulated transformers. The relatively high dielectric constant of the askeral aids in transferring the dielectric stress to the solid elements. Askeral has limited ability to recover after dielectric overstress, and thus the strength is limited in nonuniform dielectric fields. Askerals are seldom used over 34.5-kV operating voltage. They are powerful solvents; their products of decomposition are so harmful that they have been completely abandoned in transformers manufactured after the mid-1970s.

Fluorogas-Insulated Transformers. Fluorogases have better dielectric strength than nitrogen or air. Although their heat transfer characteristics are poorer than oil, they are better than nitrogen or air because of their higher density. Both dielectric strength and heat transfer capability increase with pressure; in fact, the dielectric strength at 3 atm gage pressure—where some fluorocarbon-insulated transformers operate—can approach that of oil. The gas insulation is reinforced with solid insulation used in the form of barriers, layer or disk insulation, turn insulation, and lead insulation similar to oil-immersed transformers.

It is usually economical to operate fluorogas-insulated transformers at higher temperatures than oil-insulated transformers. Suitable solid insulating materials include glass, asbestos, mica, high-temperature resins, and ceramics.

Dielectric stress on the gas is several times higher than in the adjacent solid insulation; care must be taken to avoid overstressing the gas.

Nitrogen and Air-Insulated Transformers. These are generally limited to 34.5 kV and lower operating voltages. Air-insulated transformers in clean locations are frequently ventilated to the atmosphere. In contaminated atmospheres a sealed construction is required, and nitrogen is generally used at approximately 1 atm and some elevated operating temperatures.

Design of Insulation Structures. Three factors must be considered in the evaluation of the dielectric capability of an insulation structure—the voltage distribution must be calculated between different parts of the winding, the dielectric stresses are then calculated knowing the voltages and the geometry, and finally the actual stresses can be compared with breakdown or design stresses to determine the design margin.

Voltage distributions are linear when the flux in the core is established. This occurs during all power frequency test and operating conditions and to a great extent under switching impulse conditions. (Switching impulse waves have front times in the order of tens to hundreds of microseconds and tails in excess of 1000 μ s.) These conditions tend to stress the major insulation and not inside of the winding. For shorter-duration impulses, such as full-wave, chopped-wave, or front-wave, the voltage does not divide linearly within the winding and must be determined by calculation or low-voltage measurement. The initial distribution is determined by the capacitive network of the winding. For disk and helical windings, the capacitance to ground is usually much greater than the series capacitance through the winding. Under impulse conditions, most of the capacitive current flows through the capacitance to ground near the end of the winding, creating a large voltage drop across the line end portion of the coil.

The capacitance network for shell form and layer-wound core form results in a more uniform initial distribution because they use electrostatic shields on both terminals of the coil to increase the ratio between the series and to ground capacitances. Static shields are commonly used in disk windings to prevent excessive concentrations of voltages on the line-end turns by increasing the effective series capacitance within the coil, especially in the line end sections. Interleaving turns and introducing floating metal shields are two other techniques that are commonly used to increase the series capacitance of the coil.

Following the initial period, electrical oscillations occur within the windings. These oscillations impose greater stresses from the middle parts of the windings to ground for long-duration waves than for short-duration waves. Very fast impulses, such as steep chopped waves, impose the greatest stresses between turns and coil portions. Note that switching impulse transient voltages are two types—aperiodic and oscillatory. Unlike the aperiodic waves discussed earlier, the oscillatory waves can excite winding natural frequencies and produce stresses of concern in the internal winding insulation. Transformer windings that have low natural frequencies are the most vulnerable because internal damping is more effective at high frequencies.

Dielectric stresses existing within the insulation structure are determined using direct calculation (for basic geometries), analog modeling, or most recently, sophisticated finite-element computer programs.

Allowable stresses are determined from experience, model tests, or published data. For liquid-insulated transformers, insulation strength is greatly affected by contamination and moisture. The relatively porous and hygroscopic paper-based insulation must be carefully dried and vacuum impregnated with oil to remove moisture and gas to obtain the required high dielectric strength and to resist deterioration at operating temperatures. Gas pockets or bubbles in the insulation are particularly destructive to the insulation because the gas (usually air) not only has a low dielectric constant (about 1.0), which means that it will be stressed more highly than the other insulation, but also air has a low dielectric strength.

High-voltage dc stresses may be imposed on certain transformers used in terminal equipment for dc transmission lines. Direct-current voltage applied to a composite insulation structure divides between individual components in proportion to the resistivities of the material. In general the resistivity of an insulating material is not a constant but varies over a range of 100:1 or more, depending on temperature, dryness, contamination, and stress. Insulation design of high-voltage dc transformers in particular require extreme care.

10.1.6 Cooling

Removal of heat caused by losses is necessary to prevent excessive internal temperature that would shorten the life of the insulation. The following paragraphs cover the procedure for calculating the internal temperature of oil-insulated self-cooled power transformers of conventional core-type construction

using radiators. Almost all modern power transformers have insulation systems designed for operation at 65°C average winding rise over ambient temperature and 80°C hottest-spot winding rise over ambient in an average ambient of 30°C. Older power transformers were designed for 55°C average winding rise/65°C hottest-spot winding rise over ambient.

The *average temperature of a winding* is the temperature determined by measuring the dc resistance of the winding and comparing it with the measurement previously obtained at a known temperature. The rise of the average temperature of a winding above ambient temperature is

$$U = B + E + N + T \quad (10-29)$$

where B = degrees Celsius rise of effective oil over ambient, E = degrees Celsius rise of average oil over effective oil, N = degrees Celsius rise of average coil surface over average oil, T = degrees Celsius rise of conductor over coil surface, and U = degrees Celsius rise of average conductor over ambient.

The *effective oil temperature* is the equivalent uniform temperature with equal ability to dissipate heat to the air. The effective oil temperature is approximately the average of the oil entering the top of the radiator and the oil leaving the bottom of the radiator. The oil temperature is approximately the same as the temperature of the adjacent radiator surface exposed to air. A smooth, vertical transformer-tank surface will dissipate heat to the air as follows:

$$D_B = 1.40 \times 10^{-3} B^{1.25} + 1.75 \times 10^{-3} (1 + 0.011A) B^{1.19} \quad (10-30)$$

where A = degrees Celsius ambient temperature, B = degrees Celsius effective oil rise over ambient, and D_B = watts per square inch dissipated to the air.

The first term of Eq. (10-30) covers heat transferred by convection. Usually, the radiator consists of parallel flattened tubes with limited accessibility to cooling air, and it is therefore necessary to multiply the first term by an experimentally determined friction factor (less than 1). The second term of Eq. (10-30) covers heat transferred by radiation, on the assumption of low temperature emissivity of 0.95, which applies to most painted surfaces commonly encountered. For any other value of low temperature emissivity this term should be multiplied by emissivity/0.95 (see Table 10-2). Usually, the radiator consists of parallel flattened tubes which radiate heat to each other. The net radiation of heat can be determined by considering the transformer and radiators replaced by a nonreentrant enveloping surface. If the second term of Eq. (10-30) is multiplied by the ratio of the area of the enveloping surface to actual surface (less than 1), the effect of reabsorption of radiation is eliminated. When radiation is small compared with convection, it can be assumed that $A = 25^\circ\text{C}$ and the $B^{1.19}$ can be replaced by $0.79B^{1.25}$, and Eq. (10-30) becomes

$$B = \frac{100D_B^{0.8}}{(0.44F + 0.56V)^{0.8}} \quad ^\circ\text{C} \quad (10-31)$$

where V = ratio of envelope surface area to actual surface area and F = friction factor determined by experiment.

The temperature rise of average oil over effective oil, E , is usually negligible for normal transformer designs. It may become important if (1) the center of gravity of the radiators is not elevated sufficiently above the center of gravity of the core and coils, (2) there is unusual loss in the oil space over the core such as might result from high-current leads, (3) a winding has usually restricted oil ducts, or (4) pumps are used to circulate oil through the radiator without channeling the pumped oil

TABLE 10-2 Low Temperature Total Emissivity

Aluminum, highly polished	0.08
Copper	0.15
Cast iron	0.25
Aluminum paint	0.55
Oxidized copper	0.60
Oxidized steel	0.70
Bronze paint	0.80
Black gloss paint	0.90
White lacquer	0.95
White vitreous enamel	0.95
Green paint	0.95
Gray paint	0.95
Lampblack	0.95

The temperature rise of average coil surface over average oil, N , carries the loss in the coil through a film of stationary oil into moving oil. For a horizontal pancake coil (vertical axis), most of the heat escapes through the thin oil film on the upper surface and very little heat escapes from the lower surface. On the assumption that all the heat escapes from the upper surface, the temperature rise is

where D_N = watts per square inch dissipated from the coil to the oil.

$$N = 14D_N \quad ^\circ\text{C} \quad (10-33)$$
$$T = R_T t D_N \quad ^\circ\text{C} \quad (10-34)$$

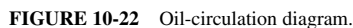
The components of the winding rise over ambient are determined from Eqs. (10-31), (10-32), or (10-33), and (10-34) by using values of watts per square inch determined from the calculated losses and the design geometry. Then the total rise is determined from Eq. (10-29).

$$w = 2.50 \times 10^{-5} \text{ ml} \quad (10-35)$$

I is established by the following relations:

$$w = G_C R_H \quad (10-37)$$

$$I = 13.5 \left(\frac{LR_H}{m} \right)^{1/2} \quad (10-38)$$



where G_C = gallons per minute rate of circulation of oil, L = watts loss, and R_H = friction opposing oil flow in pound-force per square inch per gallon per minute.

R_H is not easily evaluated except by test, but Eq. (10-38) is useful in evaluating the effect of changing L or m .

The limiting temperature rises are

$$H = B + E + I \quad (10-39)$$

$$S = B + E + N + T + I = U + I \quad (10-40)$$

where H = degrees Celsius top oil rise over ambient temperature and S = degrees Celsius hot-spot rise over ambient temperature.

Equation (10-40) gives the temperature of the top pancake coil. Values of N and T may need to be separately computed for this coil or for other coils if they have different loss density or different insulation than the main winding coils. If a coil other than the top coil is found to have higher conductor rise over adjacent oil, then appropriately reduced values of I should be used to calculate S for that coil.

Variation of temperature with load is as follows. If temperature rise conditions for rated load (or for any load) are known, temperature rises for any other load can be determined

$$B_2 = B_1 \left(\frac{L_2}{L_1} \right)^{0.8} \quad (10-41)$$

$$N_2 = N_1 \left(\frac{L_2}{L_1} \right)^{0.8} \quad (10-42)$$

$$T_2 = T_1 \frac{L_2}{L_1} \quad (10-43)$$

$$I_2 = I_1 \left(\frac{L_2}{L_1} \right)^{1/2} \quad (10-44)$$

where B_1 , N_1 , T_1 , I_1 , and L_1 correspond to the known condition and B_2 , N_2 , T_2 , I_2 , and L_2 correspond to the new condition.

The total loss should be used for L_1 and L_2 in Eqs. (10-41) and (10-44). The resistance and eddy loss only should be used for L_1 and L_2 in Eqs. (10-42) and (10-43). The exponent in Eq. (10-42) should be 1.0 for vertical pancake coils. At constant voltage the resistance loss varies with the square of the load kVA and with the resistivity as affected by average temperature of copper according to Eq. (10-25). The eddy loss varies with the square of the load and inversely with the resistivity of the copper according to Eq. (10-27). The stray loss varies with the square of the load and may be assumed to vary inversely with the resistivity of the copper, like the eddy loss. The core loss may be assumed unaffected by load or temperature. For many purposes, it is reasonable to assume that the entire load loss varies with the square of the load and with the resistivity.

Consider the following example. What is the temperature rise in a 30°C ambient at 80% load of a transformer with the following characteristics?

Load loss is 2 times no-load loss at 85°C

Load loss is assumed all resistance loss 85°C

Full-load temperature rises with 85°C losses are

$$B_1 = 45$$

$$N_1 = 15 \quad U_1 = 65$$

$$T_1 = 5 \quad S_1 = 80$$

$$I_1 = 15 \quad H_1 = 60$$

10-22 SECTION TEN

On assuming (for a trial) that the average copper temperature will be 80°C, the relative load loss is

$$(0.8)^2 \times \frac{234.5 + 80}{234.5 + 85} = 0.630$$

and the relative total loss is

$$\frac{0.630 \times 2 + 1}{3} = 0.753$$

Then

$$B_2 = 45(0.753)^{0.8} = 35.9^\circ\text{C}$$

$$N_2 = 15(0.630)^{0.8} = 10.4^\circ\text{C}$$

$$T_2 = 5 \times 0.630 = 3.2^\circ\text{C}$$

$$I_2 = 15(0.753)^{0.5} = 12.0^\circ\text{C}$$

$$U_2 = 35.9 + 10.4 + 3.2 = 49.5^\circ\text{C}$$

$$S_2 = 35.9 + 10.4 + 3.2 + 12.0 = 61.5^\circ\text{C}$$

$$H_2 = 35.9 + 12.0 = 47.9^\circ\text{C}$$

The average copper temperature is $49.5 + 30 = 79.5^\circ\text{C}$, which is close enough to the assumed 80°C .

Consider another example. What is the temperature rise in a 30°C ambient at 140% load for the same transformer? Upon assuming (for a trial) that the average copper temperature will be 140°C , the relative load loss is

$$(1.4)^2 \frac{234.5 + 140}{234.5 + 85} = 2.30$$

and the relative total loss is

$$\frac{2.30 \times 2 + 1}{3} = 1.87$$

Then

$$B_2 = 45(1.87)^{0.8} = 74.2^\circ\text{C}$$

$$N_2 = 15(2.30)^{0.8} = 29.2^\circ\text{C}$$

$$T_2 = 3 \times 2.30 = 6.9^\circ\text{C}$$

$$I_2 = 15(1.87)^{0.5} = 20.5^\circ\text{C}$$

$$U_2 = 74.2 + 29.2 + 6.9 = 110.3^\circ\text{C}$$

$$S_2 = 74.2 + 29.2 + 6.9 + 20.5 = 130.8^\circ\text{C}$$

$$H_2 = 74.2 + 20.5 = 94.7^\circ\text{C}$$

The average copper temperature is $110.3 + 30 = 140.3$, which is close enough to the assumed 140°C . These temperatures would be considered excessive for continuous loading and should not be continued for any extended time period.

Industry loading guides (ANSI/IEEE C57.92) provide tables that give winding hottest-spot temperature and top oil temperature for representative transformers over a wide range of ambient temperature and per unit loading conditions. These guides also contain a cautionary note that operation at hottest-spot temperatures above 140°C may cause gassing in the solid insulation and oil which could reduce the dielectric integrity of the transformer (Heinrichs 1979, McNutt, et al. 1980).

Transient thermal conditions must also be considered. Since transformer temperature takes many hours to stabilize after a change in loading, it is sometimes desirable to calculate the temperature during the transient period.

$$B_H = B_U - (B_U - B_0)e^{-h/h_B} \quad (10-45)$$

$$h_B = \frac{K_B(B_U - B_0)}{L_D - L_0} \quad (10-46)$$

$$\begin{aligned} K_B &= 0.06H_{CC} + 0.04H_T + 1.33G_T && \text{for nondirected flow cooling} \\ K_B &= 0.06H_{CC} + 0.06H_T + 1.93G_T && \text{for directed flow cooling} \end{aligned} \quad (10-47)$$

where B_H = degrees Celsius effective oil rise after h hours, B_0 = degrees Celsius initial oil rise, B_U = degrees Celsius ultimate effective oil rise for the new load, G_T = gallons of oil, $\epsilon = 2.718$, h = hours after the change in load, h_B = hours time constant of the transformer, H_{CC} = pounds weight of core and coils, H_T = pounds weight of tank and fittings, K_B = watthours per degree Celsius thermal capacity of the transformer, L_D = watts dissipated at the new load, L_0 = watts loss at the initial condition ($h = 0$).

Equation (10-45) applies whether B_U is greater or less than B_0 . However, if B_0 and L_0 are zero, then

$$B_H = B_U(1 - e^{-h/h_B}) \quad (10-48)$$

$$h_B = \frac{K_B B_U}{L_D} \quad (10-49)$$

The rise of average conductor over average oil ($N + T = Q$) is a single variable for transient calculations. The ultimate value is reached in 15 to 30 min

$$Q_H = Q_U - (Q_U - Q_0)e^{-h/h_Q} \quad (10-50)$$

$$h_Q = \frac{K_Q(Q_U - Q_0)}{L_0 - L_D} \quad (10-51)$$

$$K_Q = 0.05H_C \frac{a/2 + b}{b} \quad (10-52)$$

where a = square inches cross section of strand insulation, b = square inches cross section of copper strand, H_C = pounds weight of copper in winding, K_Q = watthours per degree Celsius thermal capacity of winding, L_D = watts dissipated at $h = 0$, L_0 = watts loss at $h = 0$, h = hours, h_Q = hours time constant of winding, Q_H = degrees Celsius average conductor rise over average oil after h hours, Q_0 = degrees Celsius initial average conductor rise over average oil, and Q_U = degrees Celsius ultimate average conductor rise over average oil.

Equation (10-50) applies whether Q_U is greater or less than Q_0 . However, if Q_U and L_0 are zero, then

$$Q_H = Q_0 e^{-h/h_Q} \quad (10-53)$$

$$h_Q = \frac{K_Q Q_0}{L_D} \quad (10-54)$$

Now consider another example. If the transformer in the previous example operates in a 30°C ambient at 80% load until ultimate temperature conditions are established and then operates at 140% load, what will be the conditions after 4 h at 140% load? Assume nondirected flow cooling. It is now necessary to specify additional characteristics of the transformer as follows:

$$H_C = 20,000 \quad a = 0.018$$

$$H_{CC} = 100,000 \quad b = 0.090$$

$$H_T = 30,000$$

$$G_T = 10,000$$

$$\text{Total loss} = 150,000 \text{ W at } 85^\circ\text{C}$$

$$\text{Then} \quad K_B = 0.06 \times 100,000 + 0.04 \times 30,000 + 1.33 \times 10,000 = 20,500 \quad (10-55)$$

Assume that the average winding temperature after 4 h is 125°C.

$$L_D = \frac{2 \times (1.4)^2 (234.5 + 125) / 319.5 + 1}{3} 150,000 = 270,540 \text{ W}$$

$$L_0 = 0.753 \times 150,000 = 112,950 \text{ W}$$

$$h_B = \frac{20,500 (74.2 - 35.9)}{270,540 - 112,950} = 4.98 \text{ h}$$

$$B_H = 74.2 - (74.2 - 35.9)e^{-4/4.98} = 57.0^\circ\text{C}$$

$$\left. \begin{array}{l} N_H = 29.2 \\ T_H = 6.9 \\ I_H = 20.5 \end{array} \right\} \text{ (these reach ultimate value before 4 h)}$$

$$U_H = 57.0 + 29.2 + 6.9 = 93.1^\circ\text{C}$$

$$S_H = 57.0 + 29.2 + 6.9 + 20.5 = 113.6^\circ\text{C}$$

$$H_H = 57.0 + 20.5 = 76.5^\circ\text{C}$$

Consider the following example of a load cycle. If the transformer examined in the preceding example operates in a 30°C ambient on a daily cycle of 20 h at 80% load and 4 h at 140% load, what are the temperature rises at the end of the 140% load period? Since the transformer time constant was approximately 5 h, it would be reasonable to assume that the oil temperature will have essentially stabilized after 20 h at 80% load. (The time constant for the transient from 140% load to 80% load will be essentially the same as the time constant for the transient from 80% load to 140% load.) As a result, the temperature rises at the end of the 140% load period during this cycle will be the same as those found in the previous example. Figure 10-23 shows the complete set of time-temperature curves for the 24-h cycle.

The short-circuit temperature rise is calculated on the assumption that all heat generated in the copper is stored in the copper until the short circuit is over

$$C_2 = 309.5 \times \left\{ \left[\left(\frac{C_1 + 234.5}{309.5} \right)^2 + g \right] e^{M^2 s / 10,800} - g \right\}^{1/2} - 234.5 \quad (10-56)$$

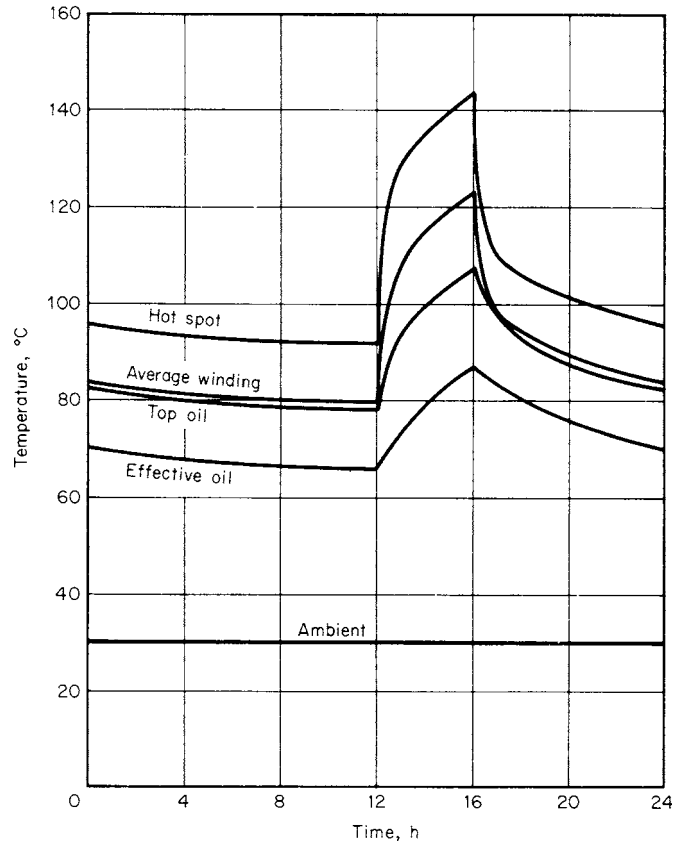


FIGURE 10-23 Transformer temperatures during the daily load cycle.

where, C_1 = degrees Celsius average temperature of winding at start of short circuit, C_2 = degrees Celsius average temperature of winding at end of short circuit, M = rms kiloamperes per square inch current density, s = seconds duration of short circuit, and g = ratio of eddy loss to resistance loss in winding at 75°C.

The temperature resulting from any short circuit may be read directly from Fig. 10-24, which is plotted from Eq. (10-56).

For example, if a short circuit resulting in 50 kA/in² current density is held for 3.5 s in a winding with 10% eddy loss ($g = 0.1$) at 75°C, and with a starting temperature of 75°C, what is the average temperature of the winding at the end of the short circuit?

On the curve for $g = 0.1$, at 75°C, the value of M^2s is 5300.

$$5300 + 50^2 \times 3.5 = 14,050$$

On the curve for $g = 0.1$, at $M^2s = 14,050$, the temperature is 246°C.

Fan-cooled transformers use external fans to improve heat dissipation from the radiators, and sometimes internal pumps to circulate the oil through the radiators (and sometimes also through cooling ducts in the core and coils). With fan cooling the effective oil-temperature rise B is determined from test data on the particular arrangement, instead of Eq. (10-31). With oil pumps I is determined from Eq. (10-38). It is usually possible to obtain 67% more capacity with fans and pumps running.

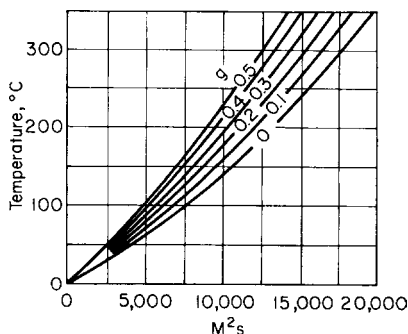


FIGURE 10-24 Temperature of windings after short circuit, with all heat stored, where g = ratio of eddy current loss to resistance loss at 75°C, M = rms kiloamperes per square inch current density, and s = seconds duration of short circuit. *Example:* For initial temperature of 75°C from the curve of $g = 0.1$, read $M^2s = 5300$. For $M = 50$ and $s = 3.5$: $(50)^2 \times 3.5 = 8750$. Total $M^2s = 14,050$. Then, from curve of $g = 0.1$, read final temperature: 246°C.

Operation at high altitude increases the effective oil rise of air-cooled transformers. ANSI C57 provides for a compensating correction of 0.4% of rated kVA for self-cooled transformers or 0.5% of rated kVA for forced-air-cooled or forced-oil-cooled transformers for each 330 ft of additional altitude above 3300 ft altitude.

Effect of Tank Color. Most paint used on transformers has a low temperature emissivity of about 0.95. Metallic surfaces, particularly polished surfaces, have less low temperature emissivity and will cause correspondingly higher oil-temperature rise. The same is true of aluminum or bronze paint. For these cases, Eq. (10-31) can be used with V' substituted for V , where V' is $V/0.95$ multiplied by the low temperature emissivity from Table 10-2. On large power-transformers with many radiators or heat exchangers the effect is small.

For transformers exposed to intense sunlight, the additional temperature rise resulting from the use of aluminum paint is largely offset by the fact that aluminum paint absorbs only about 55% of the impinging solar radiation, whereas most commonly used paints absorb about 95%.

10.1.7 Load-Tap Changing

Ratio Changes with Shifted Taps. In transformers designed for maintaining a constant voltage on a power system, the ratio of transformation is usually changed by increasing or decreasing the number of active turns in one winding with respect to another winding. Since the turn ratio of the transformer must be changed without interfering with the load, means are provided for shunting the load current from one winding tap to the next. For this purpose, an auxiliary *preventive autotransformer* is generally used, designed to limit the resulting circulating current to a safe value during the interval when two adjacent taps are bridged. Because of the circulating and the load current which passes through the current-limiting impedance, arcing always takes place as the power circuit is transferred from tap to tap.

Although a variety of switching equipment and transformer connections have been used for the purpose of changing taps under load, the underlying principle remains unchanged and is shown by the transformer connection in Fig. 10-25.

Example. To move from transformer tap A to B , it is first necessary to close the circuit to B , as shown in Fig. 10-25, before opening the circuit at A . During the interval when A and B are both

Forced-oil-cooled transformers use external oil-to-air heat exchangers requiring both air fans and oil pumps for all operating conditions. The effective oil rise B is calculated from the characteristics of the oil-to-air heat exchanger, and I is determined from Eq. (10-36). Forced-cooled transformers have no continuous load capacity without pump and fans.

Water-cooled transformers usually have the oil withdrawn from the transformers at the top of the tank, pumped through an external cooler, and returned to the bottom of the tank. The temperature drop of the oil in passing through the cooler is

$$Y = \frac{L}{G_c \times 111} \quad (10-57)$$

where Y = degrees Celsius drop of oil in cooler, L = watts loss, and G_c = gallons-per-minute rate of circulation of oil.

The effective oil-temperature rise B may be calculated from the characteristics of the oil-to-water heat exchanger. The top oil rise over average oil, I , is $Y/2$. The other components of temperature rise are calculated as for a self-cooled transformer.

closed on adjacent taps, a circulating current flows through and is limited by the impedance on the loop composed of the tap winding AB and autotransformer C . With both ends of the autotransformer connected to A , the load current divides equally between the two halves of the autotransformer. Since the current flows in opposite directions, a negligible amount of reactance is introduced into the circuit and the only loss is the I^2R due to the 50% load current in each half of the autotransformer winding. With A closed and B open, all the load current flows through one-half of the autotransformer, magnetizing the autotransformer and thereby introducing into the circuit the induced voltage. It is important, therefore, that the magnetizing reactance be kept as low as possible to avoid excessive arcing duty on the circuit-interrupting device.

With A and B closed on adjacent taps, the tap voltage e is impressed on the autotransformer C and causes a circulating current to flow through the impedance loop. Because of the autotransformer action, a voltage midway between A and B is impressed in the circuit. The load current again divides equally through the autotransformer windings.

To avoid an excessive voltage drop through the autotransformer when one side is open and at the same time to keep the circulating current at a low level when in the bridging position, the autotransformer is usually designed with an air gap in the magnetic circuit to get a magnetizing current of approximately 60% of the normal full-load current.

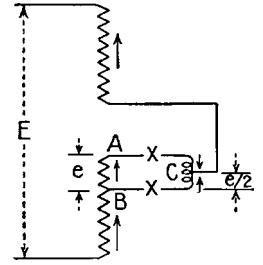


FIGURE 10-25 Bridging position for ratio change under load.

Voltage across Autotransformers. Figure 10-26 shows the voltage relations across an autotransformer and switching contacts during a tap-changing cycle using an autotransformer designed for 60% circulating current and with 100% load current at 80% power factor flowing through it. Perfect interleaving between the autotransformer halves is assumed, and the voltage drop due to resistance of the autotransformer winding is neglected.

A study of Fig. 10-26 will disclose the fact that increasing the magnetizing reactance of the autotransformer to reduce the circulating current will

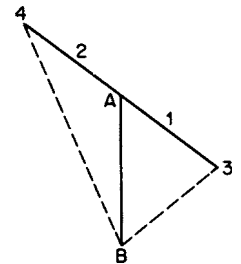


FIGURE 10-26 Vector relations for bridging position AB —voltage across adjacent taps; $A-1$ and $A-2$ —reactance volts due to load current in only half the autotransformer winding; $A-3$ and $A-4$ —induced voltage across full autotransformer winding; $B-4$ —voltage ruptured when bridging position is ruptured at A (Fig. 10-25); $B-3$ —voltage ruptured when bridging position is ruptured at B (Fig. 10-24).

1. Increase the voltage across the full autotransformer winding
2. Increase the voltage to be ruptured
3. Introduce undue voltage fluctuations in the line

Since $B-4$ and $B-3$ represent the voltages appearing across the arcing contacts when the bridging position is opened at A and B , the voltage-rupturing duty will increase with

1. Increase in voltage between adjacent taps
2. Increase in load
3. Decrease in power factor of the load
4. Decrease in the magnetizing current for which the autotransformer is designed

Load-Tap-Changer Motor Mechanisms. The mechanism which drives the tap changer, and the control of this mechanism, must be designed so that a tap change, once initiated, is certain to be completed.

The mechanical coupling between the operating motor and the tap-changing switches may be through fixed-ratio gears, Geneva gears, cams, springs, or combinations of these. All mechanisms require means for keeping the motor energized until the change of tap is accomplished and for bringing the tap changer to rest on each operating position. The degree of permissible coasting of the motor is determined by the motor mechanism and the switch design.

The need for extremely accurate stopping of the motor is avoided by arranging the parts so that the motor may coast somewhat after the operating position is reached without moving the tap changer

around the operating position. This may be accomplished by the inactive sectors of Geneva gears or cams or by the motor travel inherently involved in recharging a spring. Motor mechanisms are provided with limit switches and mechanical stops to prevent operation beyond the limit positions. Operation counters and position indicators are standard auxiliaries on most tap changers. On large station-type units where the control devices are generally mounted on a remote-control panel, remote position indicators, either of the self-synchronizing type or of the digital type are generally used.

Automatic Control for Tap Changers. It is usual practice to use some sort of voltage measuring device to control the operation of the motor which drives the tap changer. Such devices may be mechanical, balancing the force of a solenoid actuated by the voltage against weights or springs, or they may be an electrical network, usually a bridge circuit which balances against the voltage of a Zener diode. With either type of device, a voltage higher than a desired upper limit will start the tap-changer driving motor to change to the next lower tap voltage; similarly, a voltage lower than the desired lower limit will cause a change to the next higher tap.

The circuit usually includes a time delay to prevent tap changes, which would occur unnecessarily during very short time variations in voltage. It also may include a line drop compensator to facilitate maintaining the voltage within a given band at a point (load center) some distance from the transformer. The line-drop compensator introduces a signal into the voltage regulating relay circuitry. This represents the voltage drop due to line impedance between the transformer and the load center.

The voltage-regulating relay (or contact-making voltmeter) should be adjusted so that the voltage bandwidth, or spread between voltages at which the raising and lowering contacts close, will be not less than the percentage transformer tap plus an allowance for irregular voltage variations. For example, a tap-changing transformer with $1\frac{1}{4}\%$ taps should have a minimum voltage bandwidth of approximately $1\frac{1}{4}\% + \frac{1}{2}\% = 1\frac{3}{4}\%$.

In addition, the voltage-regulating relay may contain a component for use when load tap-changing transformers are operated in parallel. In this case, the tap changers must be controlled so that they are approximately on the same tap position. The component, a paralleling reactor, is used with external circuitry to detect, and generate a signal to minimize, circulating current that results when the tap changers are not on like positions.

Voltage Control, a Part of the Power Transformer. The simplest and generally the least expensive connection for voltage control is to provide the necessary taps in the power transformer. For single- or 3-phase delta connection the taps are preferably located on the interior of the winding (Fig. 10-27) so as to avoid the abnormal voltage stresses to which end coils are usually subjected. In the Y connection the taps may be placed at the neutral end of the winding, and if the neutral is to be solidly grounded, it becomes possible, by locating the taps next to ground, to use load changers designed with greatly reduced insulation; thus, for example, 15-kV apparatus may be placed in the grounded neutral end of a much higher-voltage circuit.

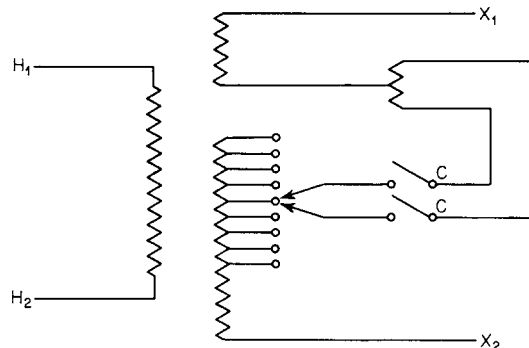


FIGURE 10-27 Tap-changing equipment in the middle of the winding.

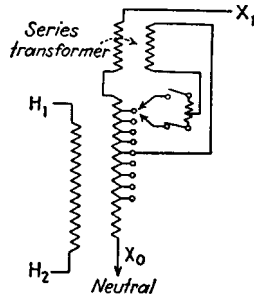


FIGURE 10-28 Tap-changing circuit with taps located in the interior of the transformer winding and an auxiliary series transformer to bring the current and voltage duty on equipment within rating limits.

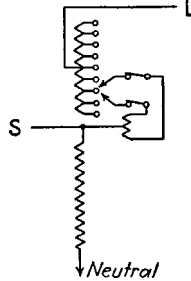


FIGURE 10-29 Regulating single-core autotransformer with taps located in the series winding and circuit connected for boost and buck.

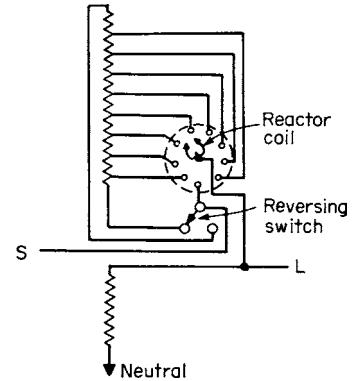


FIGURE 10-30 Regulating single-core autotransformer with a reversing switch to obtain buck and boost.

If the rated current of the transformer exceeds that of the switching equipment, a series transformer may be used (Fig. 10-28). Excitation is derived from taps inserted in the secondary of the power transformers, and by means of the series transformer, the desired voltage is inserted into the circuit. Thus, if a ratio of 3:1 exists in the series transformer, the current handled by the switching equipment becomes one-third of the current in the line.

Regulating Transformers (Single-Core). When a power transformer is not available or it is not desirable to equip the power unit with voltage control, regulating autotransformers are used. In the simplest of these, the necessary taps and switches are placed in the series winding of an autotransformer (Fig. 10-29). For 3-phase circuits, in order that the derived voltage may be in phase with circuit voltage, a Y connection is commonly used, and hence all the precautions necessary to safeguard the operation of Y-connected autotransformers should be observed. A tertiary winding may or may not be provided, depending on circuit conditions. As the series winding is inserted in the line, adequate insulation must be provided for the tap-changing equipment and taps against the abnormal voltages to which the circuit is subjected.

Economy in transformer size may be obtained by means of a reversing switch which functions to reverse the connections to the series winding when the regulator is passing through the neutral position. The circuit is so designed and the mechanical sequence is such that the reversing switch operates without rupturing current. The connection diagram (Fig. 10-30) shows the load tap changer provided with nine taps, which gives 17 full-cycle or 33 half-cycle positions. The ratio adjuster is designed with contacts uniformly spaced on the circumference of the circle so as to permit motion through two revolutions.

The Series Transformer. In many instances the voltage of the circuit is greater than that for which the switching equipment is designed, and in others the current to be handled exceeds the safe limits of operation. In either case, voltage control can be obtained without the design of special switching equipment by using an insulating series transformer (Fig. 10-31) in addition to the exciting transformer, the combination functioning, as far as the circuit is concerned, like an autotransformer. The primary of the exciting transformer is generally connected in Y in order that the derived voltages may be in phase with circuit voltages. The secondary of the exciting transformer provided with the regulating taps is usually connected in delta. The local circuit, consisting of the secondary of the exciting transformer with its taps and the primary of the series transformer being insulated from the main circuit, may be designed for the voltage and current best suited for the available switching equipment. Because of the additional cost and losses of the series transformer, it is used only when the voltage

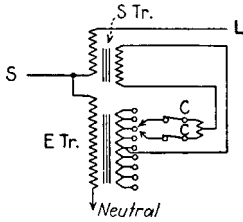


FIGURE 10-31 Exciting transformer with taps in the secondary and a series transformer forming complete isolation for tap-changing equipment.

or current limitations of the switching equipment demand it and when the control cannot be inserted in the grounded neutral of the transformer bank.

Tap-Changer Designs for Moderate kVA and Current. In the smaller ratings, where both the voltage and the current are moderate, the energy to be ruptured in switching from tap to tap becomes relatively so small that light and simple equipments are feasible. A variety of mechanical designs, together with special circuits, has been evolved with the purpose of providing simpler, smaller, and inherently less expensive equipments. The following may be noted:

1. Designing the tap changer so that it is capable of rupturing the current directly on the same switches which select the taps
2. Designing the circuit so that the tapped winding is reversed in going from maximum to minimum range, thereby securing a substantial reduction in the rating of core and coils for a given output
3. Using higher switching speed, by means of which the life of the arcing contacts is increased

Tap Changers Designed to Interrupt Current. The contactors *C* (Fig. 10-27) operate to open the switching circuits so that there is no interrupting duty on the selector contacts which connect to the transformer taps. When the rated current is moderate, it becomes possible to rupture the current directly on the tap-selector switches and thus obtain a major economy in the cost of the mechanical equipment. This method is shown in Fig. 10-30.

High-Speed Switching. Large units include contactors with high-speed contacts which serve as extinction devices that are specially designed to repeatedly interrupt the high currents and voltages encountered. They may be single- or multiple-break contactors operating in oil or in air with magnetic-arc chutes, or oil-blast contactors. Vacuum switches with their longer life (reduced maintenance) have

become widely used. In small units, however, the arcing duty is mild. It is nevertheless necessary to keep in mind that mild arcing duty in the smaller equipment is partly offset by the likelihood of greater frequency of operation. Such units are usually equipped with full automatic control; they are likely to be located on distribution circuits where the voltage is more erratic. Many of them are located on the lines at considerable distances from substations, and some of them are placed on poles. It is desirable, therefore, to reduce maintenance to a minimum. For these reasons, it is necessary to provide means for high-speed switching on the smaller units where the tap-selector switches are used to rupture current. High-speed action of the tap-changer switches is obtained through Geneva gears or cams which bring the contact fingers to the required high speed at the moment of parting or through a spring drive in which the motor is used to store energy with the release of a spring snapping the contact fingers from one shelf to the next. By these means, the duration of the switching arc may be reduced to one or two contactors correspondingly reducing the amount of contact burning and increasing the life of the contacts.

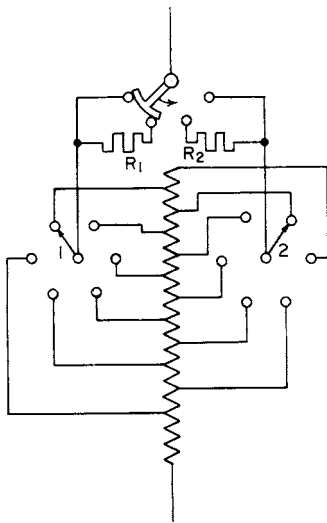


FIGURE 10-32 Tap-changing circuit employing tap selectors and contact, or diverter switch, and resistors to bridge the taps during switchover.

Use of Resistors. Another method, used more frequently in load tap changers of European design, makes use of resistors to bridge the tap instead of a preventive autotransformer. Figure 10-32 shows the tap selectors 1 and 2 connected to

alternate taps in the winding. The contactor, or diverter switch, shown connected to 1 and R_1 , progressively connects only to R_1 , then to R_1 and R_2 , then to R_2 , and finally to R_2 and tap selector 2. For the next tap change, tap selector 1 moves to an adjacent tap and is then followed by the diverter switch operating in a reverse manner from R_2 and 2 back to R_1 and 1. Since the resistors are designed to carry current for only a very short time, the diverter switch is usually spring-actuated and moves through its sequence in a few cycles of 60-Hz current. This method has the advantage of relatively small-size resistors but requires a transformer tap for each operating voltage, while the autotransformer circuit uses the tap bridging position for an operating voltage and thus requires half the number of transformer taps.

Applications for Voltage Control and Equipment. The control of transformer ratio under load is a desirable means of regulating the voltage of high-voltage feeders and of primary networks. It may be used for the control of the bus voltage in large distributing substations. It finds a wide field of application in controlling the ratio on step-up transformers operating from power stations whose bus voltage must be varied to suit local distribution.

In industrial work, it is used for the control of current in a variety of furnace operations and electrolytic processes. It also furnishes a convenient means for voltage regulation of concentrated industrial loads.

A lot of load tap-changer equipment is installed at points of interconnection between systems or between power stations, in order to control the interchange of reactive current, or, in other words, to control the power factor in the tie line. This reactive current may be highly undesirable, especially as it may add to the burden on a fully loaded generating system. It can be increased, eliminated, or reversed by inserting a suitable small ratio of transformation between the systems. It can be varied in amount and in direction of flow to suit varying system conditions, if this ratio is variable and under the control of a station operator. Inserting such a ratio of transformation in a tie line by means of tap-changing equipment is equivalent in its effect on the flow of reactive current to raising or lowering the voltage on one of the systems. Current can be exchanged at any power factor from zero lag to zero lead, without interfering with the voltage maintained on either system.

Transformers for Phase-Angle Control. Tap-changing equipment is sometimes used in a loop system, for phase-angle control, for the purpose of obtaining minimum losses in the loop due to unequal impedances in the various portions of the circuit.

Transformers used to derive phase-angle control do not differ materially, either mechanically or electrically, from those used for inphase control. In general, phase-angle control is obtained by interconnecting the phases, that is, by deriving a voltage from one phase and inserting it in another.

The simple arrangement given in Fig. 10-33a illustrates a single-core delta-connected autotransformer in which the series windings are so interconnected as to introduce into the line a quadrature voltage. One phase only is printed in solid lines so as to show more clearly how the quadrature voltage is obtained. The terminals of the common winding are connected to the midpoints of the series winding in order that the inphase voltage ratio between the primary lines ABC and secondary lines XYZ is unity for all values of phase angle introduced between them.

As large high-voltage systems have become extensively interconnected, a need has developed to control the transfer of real power between systems by means of phase-angle-regulating transformers. The most commonly used circuit for this purpose is the two-core, four-winding arrangement shown in Fig. 10-33b. The high-voltage common winding is Y-connected, with reduced insulation at the neutral for economy of design, and a series transformer is employed so that low-voltage-switching equipment may be used.

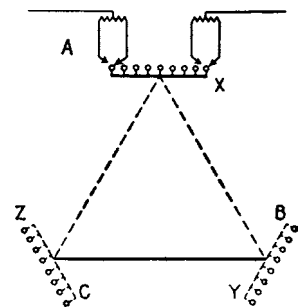


FIGURE 10-33a Phase-shifting regulating transformers; single-core delta-connected common winding for low-voltage systems.

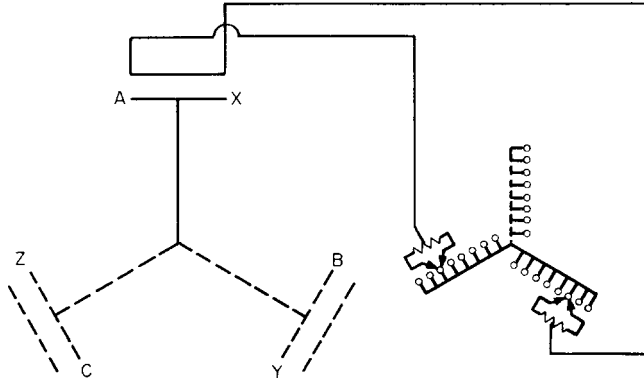


FIGURE 10-33b Phase-shifting regulating transformer; two-core Y-connected common winding for high-voltage systems.

10.1.8 Audible Sound

Source of Sound. Transformers, although they are classed as static apparatus, vibrate and radiate audible sound energy. In general, there are three different sources of transformer noise:

1. *Core vibration due to magnetostriction.* Core steel laminations undergo elongations and contractions (magnetostriction) as flux through them varies. This magnetostriction is nonlinear and independent of flux direction. Hence, noise is emitted in even multiples of the excitation frequency, that is, 120, 240, 360 Hz, etc., for a 60-Hz power system. The harmonic components decrease in magnitude as the mode of vibration goes up. However, an overexcited transformer or core-resonance may produce abnormally high third or higher harmonic frequencies.
2. *Noises from cooling equipment.* All rotary machinery on a transformer, including fans and pumps, produces noise with a broadband frequency spectrum. This “white noise” can have various magnitude and directionality depending on the design of the fans and pumps and on their arrangement.
3. *Coil vibration from energization.* Coils in a transformer are under cyclical stresses due to stray fluxes. The resultant motion resembles a vibrating spring and can also emit noise with harmonics of 120 Hz. However, this component is generally much lower than the previous two sources unless the transformer has a low induction level and high power ratings.

Sound Measurement. Sound waves produce small fluctuations in the atmospheric pressure which are sensed by the human ear.

Sound-level-measuring equipment as specified by ANSI Standard S1.4 consists of a microphone, amplifier, frequency weighting network, and indicating meter.

The most common type is A-weighting (Fig. 10-33c). It represents the sensitivity of the young adult ears to moderate sound levels over most of the audible spectrum. A linear response gives the actual sound intensity level. One-third octave and narrowband sound-level measurements are used to identify the source of an unexpectedly noisy transformer.

Standard Transformer Sound Level. ANSI/IEEE C57.12.90 specifies the method for measuring the average sound level of a transformer. The measured sound level is the arithmetic average of a number of readings taken around the periphery of the unit. For transformers with a tank height of less than 8 ft, measurements are taken at one-half tank height. For taller transformers, measurements are taken at one-third and two-thirds tank height. Readings are taken at 3-ft intervals around the string periphery of the transformer, with the microphone located 1 ft from the string periphery and

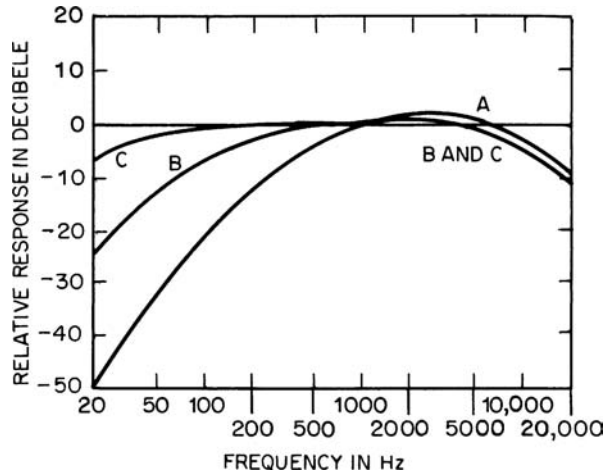


FIGURE 10-33c Weighting curves; A-weighting reduces the intensity of noise toward the lower end of the audible spectrum.

6 ft from fan-cooled surfaces. The ambient must be at least 5 and preferably 10 dB below that of the unit being measured. There should be no acoustically reflecting surface, other than ground, within 10 ft of the transformer. The A weighting network is used for all standard transformer measurements regardless of sound level.

NEMA Publication TR 1 contains tables of standard sound levels. For oil-filled transformers, from, 1000 to 100,000 kVA, self-cooled (400,000 kVA, forced-oil-cooled) standard levels are given approximately by Eq. (10-58)

$$L = 10 \log E + K \quad (10-58)$$

where E = equivalent two-winding, self-cooled kVA (for forced-oil-forced-air-cooled units, use $0.6 \times$ kVA), K = constant, from Table 10-3, and L = decibel sound level.

Example. A transformer rated 50,000 kVA self-cooled, 66,667 kVA forced-air-cooled, 83,333 kVA forced-oil-forced-air-cooled, at 825 kV BIL, would have standard sound levels of 78, 80, and 81 dB on its respective ratings.

Public Response to Transformer Sound. The basic objective of a transformer noise specification is to avoid annoyance. In a particular application, the NEMA Standard level may or may not be suitable, but in order to determine whether it is, some criteria must be available. One such criterion

TABLE 10-3 Values of K for Eq. (10-58)

High-voltage winding BIL, kV	Self-cooled and water-cooled ratings	Forced-air and forced-oil-forced-air-cooled 25% to 35% above self-cooled rating	Forced-air and forced-oil-forced-air-cooled 67% above self-cooled rating or without self-cooled rating
350 and below	28	30	31
450 to 650	30	32	33
750 to 825	31	33	34
900 to 1050	32	34	35
1175	33	35	36
1300 and above	34	36	37

is that of audibility in the presence of background noise. A sound which is just barely audible should cause no complaint.

Studies of the human ear indicate that it behaves like a narrowband analyzer, comparing the energy of a single frequency tone with the total energy of the ambient sound in a critical band of frequencies centered on that of the pure tone. If the energy in the single-frequency tone does not exceed the energy in the critical band of the ambient sound, it will not be significantly audible. This requirement should be considered separately for each of the frequencies generated by the transformer core.

The width of the ear-critical band is about 40 Hz for the principal transformer harmonics. The ambient sound energy in this band is 40 times the energy in a 1-Hz-wide band. The sound level for a 1-Hz bandwidth is known as the "spectrum level" and is used as a reference. The sound level of the 40-Hz band is 16 dB ($10 \log 40$) greater than the sound level of the 1-Hz band. Thus, a pure tone must be raised 16 dB above the ambient spectrum level to be barely audible.

The transformer sound should be measured at the standard NEMA positions with a narrow-band analyzer. If only the 120- and 240-Hz components are significant, an octave-band analyzer can be used, since the 75- to 150-Hz and 150- to 300-Hz octave bands each contain only one transformer frequency. The attenuation to the position of the observer can be determined.

The ambient sound should be measured at the observer's position. For each transformer frequency component, the ambient spectrum level should be determined. An octave-band reading of ambient sound can be converted to spectrum level by the equation

$$S = B - 10 \log C \quad (10-59)$$

where B = decibels octave-band reading, C = hertz octave bandwidth, and S = decibels spectrum level.

Example. Consider the following case:

Transformer sound at 120 Hz by NEMA method = 72 dB

Transformer-sound attenuation to observer = 35 dB

Ambient sound at the 75- to 150-Hz octave band = 36 dB

$72 - 35 = 37$ dB at the observer's position

$36 - 10 \log (150 - 75) = 17.3$ -dB ambient spectrum level

The 120-Hz transformer sound at the observer's position exceeds the ambient spectrum level by 19.7 dB. This is 3.7 dB greater than the 16-dB differential which would result in bare audibility; thus the transformer sound will be audible to the observer.

When transformer sound exceeds the limits of bare audibility, public response is not necessarily strongly negative. Some attempts have been made to categorize public response on a quantitative basis when the sound is clearly audible (Schultz and Ringlee 1960). For a case where specific knowledge of transformer- and ambient-sound-level frequency composition is not available, some more general guidelines are useful. Typical average nighttime ambient-sound levels for certain types of communities have been established. These are 30 dB for a "quiet suburban," 35 dB for a "residential suburban," and 40 dB for a "residential urban" community. All sound levels are based on the A scale of weighing. Calculations for typical transformer frequency distributions have been made to determine the nighttime transformer noise which will be audible 50% of the time in these communities. The results are 24 dB for quiet suburban, 29 dB for residential suburban, and 34 dB for residential urban. The NEMA standard sound level can be corrected for attenuation with distance to the nearest observer and checked against the above guides for audibility.

The broadband sound from fans, pumps, and coolers has the same character as ambient sound and tends to blend in with the ambient. While the noise from cooling equipment may be audible to a neighboring observer, it will seldom, if ever, cause a complaint.

Sound Attenuation with Distance. A point source in a free field radiates sound in spherical waves. The resultant sound pressure varies inversely with the square of the distance from the source; thus

the sound level is reduced by 6 dB for each doubling of distance. The sound of auxiliary cooling equipment follows this relation for decrement with distance, since it is the sum of point-source sound contributions.

The transformer tank, which radiates vibrational energy from the core, is a more complex sound source and does not appear as a point source except at substantial distance from the tank. The modes of tank vibration are complicated, and various parts of the tank may act as independent sources, with different amplitudes, phase relations, and frequencies. Studies of scale models (Johnson et al. 1956) and full-size units have uncovered certain useful relationships as follows:

$$A = 20 \log \frac{2.83 D}{Q} \quad (10-60)$$

$$Q = 1.7(WH)^{1/2} \quad (10-61)$$

where A = decibels attenuation for distance exceeding Q , D = distance from transformer to observer, H = height of transformer tank, Q = critical distance from transformer beyond which it appears as a point source, and W = width of transformer tank perpendicular to a line from transformer to observer.

Equations (10-60) and (10-61) apply in the absence of wind, temperature gradients, and reflecting surfaces other than ground. Each of these factors may significantly influence the observed sound level at a distance from the source, but not always in predictable fashion.

Site Selection. There are a number of methods available for avoiding transformer-noise complaints. Some of the discussion in the previous paragraphs suggests that potential noise problems should be considered when the substation site is selected. It may be possible to take advantage of attenuation with distance to reduce the transformer sound at the nearest observer position to an inaudible level. It may also be possible to choose the site in a location where the normal ambient noise will mask the transformer sound. If these possibilities are kept in mind during the planning stages, more expensive solutions to noise problems may be avoided later.

Design Measures. Manufacturers have at their disposal a variety of means of obtaining sound reduction. Most measures aim at reducing noise generation.

1. *Reducing core vibration.* Since magnetostriction is a function of flux intensity, a manufacturer's first option is to reduce induction levels of transformers. This has an additional advantage of reducing no-load losses. Alternatively, grades of steel having a different magnetostrictive characteristics can be substituted for the same induction-level design. A step-lap design can also reduce noise emission from joints. Finally, the designer has to anticipate the natural frequencies of the core mechanical structure and avoid their coincidence with harmonics of 120 Hz.
2. *Reducing cooling equipment noises.* The most significant noise reduction measure for cooling equipment is to reduce fan rotational speed or adjust the fan blade incidence angle. There is ample supply of low-noise designs, ranging from low speed to encased fans, from which manufacturers can choose.

When all possibilities of noise emission are exhausted and still further noise reduction is required, some sort of a mass-damper or absorption system has to be incorporated on or outside the tank structure. Moderate reductions can be realized by the use of barriers within the tank. Some of these are "soft" barriers, which operate on the principle of absorbing vibrational energy from the core and reducing its transmission to the tank. Others are "mass" barriers, which operate on the principle of loading the tank to decrease its magnitude of vibration for given energy transmission from the core. To achieve large sound reductions (as much as 25 to 30 dB), some manufacturers employ complete external enclosures of steel. For smaller substation units, these enclosures can be preassembled and shipped in place over the transformer tank.

Improving Existing Installation. To reduce the sound level of an existing transformer, the most satisfactory method has been found to be the erection of barrier walls on one or more sides of the transformer. The attenuation which can be achieved depends on the transmission loss through the

barrier, the diffraction over and around the barrier, and the pressure buildup between the tank and the barrier.

Transmission loss through a barrier wall is a function of the mass of the wall. Structural requirements of most practical masonry barriers ensure sufficient mass to produce 25 to 40 dB attenuation through the wall. The effectiveness is usually limited by diffraction around the edges of the barrier. A theoretical method for calculation of attenuation as limited by diffraction has been formulated as follows:

$$N = \frac{2}{\lambda} [(M^2 - U^2)^{1/2} - M + (G^2 - U^2)^{1/2} - G] \quad (10-62)$$

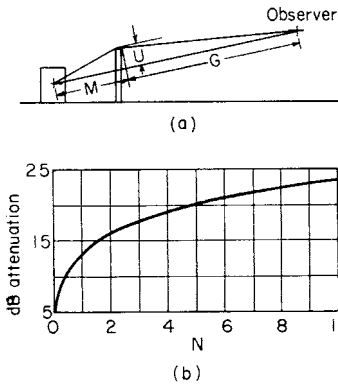


FIGURE 10-34 Effectiveness of a barrier in reducing noise level: (a) identification of dimension for calculation of the dimensionless parameter N from Eq. (10-62); (b) determinations of attenuation in decibels.

where M , U , and G are as defined in Fig. 10-34, in any convenient unit (feet or inches), λ = wavelength of harmonic under investigation, in units consistent with M , U , and G , and N = dimensionless parameter given in Fig. 10-34.

The calculation procedure is to determine N from the equation and then find the corresponding attenuation from Fig. 10-34b.

Test results on models and full-size transformers with two- and three-wall barriers correlate reasonably with Eq. (10-62). Data on four-wall enclosures generally do not correlate. It has been found that approximately 10-dB attenuation can be achieved with a four-wall enclosure having walls 5 ft higher than the transformer.

Enclosures with fewer than four walls should extend at least a distance M beyond the tank, so that attenuation will be limited by diffraction over the top rather than around the ends of the barrier. It should be noted that the sound level on the open side of this type of enclosure will be increased above what it was without the enclosure. Energy is redirected from the critical side of the transformer to the less critical side.

The effective attenuation of an enclosure can be reduced by pressure buildup between the tank and the barrier. The buildup is the result of reflection from hard wall surfaces and reinforcement of direct and reflected waves. Buildup will be most pronounced for spacings between tank and barrier walls which are multiples of the half wavelength of any of the principal sound frequencies. Such spacings should be avoided. Sound-absorbent lining on the interior surface of the barrier walls is helpful in reducing or eliminating buildup.

Masonry enclosures can also be used to hide substation transformers and associated equipment and in that way alleviate complaints which are based on appearance in addition to noise. Some utilities use a three-sided enclosure which resembles the houses in the neighborhood (Buck 1959). A casual observer on the street may not detect the presence of the substation.

10.1.9 Partial Discharges

Partial discharges may take place in liquid or gaseous dielectrics when the dielectric stress at the point of maximum stress concentration reaches the breakdown level but when complete breakdown of the dielectric is prevented because the dielectric stress decreases very rapidly away from the point of maximum stress concentration or because a solid dielectric intervenes. One form of such partial discharge, in air around a small conductor at high voltage, has been called "corona" because of its appearance as a visible glow around the conductor surface.

The local breakdown in the region of stress concentration ionizes a path (forms a streamer) in a very short time (microseconds), effectively short-circuiting a small region of the dielectric, and a pulse of current appears in the main dielectric circuit, reflecting the instantaneous short-circuiting of part of the circuit capacitance.

Partial discharges usually are accompanied by chemical decomposition of the liquid or gas, and sometimes they cause erosion of the adjacent solid insulation. A partial discharge in oil usually causes chemical breakdown, with the formation of carbon and gas, and unless the gas is immediately able to escape, more severe discharges in the gas itself may lead to complete breakdown of the insulation structure.

The presence of gas bubbles in the insulation of an oil-insulated transformer may result in partial discharges; this is the reason for particular attention to filling transformers with oil under vacuum.

Partial discharges may also be caused by wet fibers or any small conducting particles which distort the electric field and cause local points of stress concentration.

Partial discharges can be detected when they occur within the insulation of a transformer by any of a number of schemes which detect or measure either the pulse of current or the momentary loss of voltage at the transformer terminal. The charge transfer at a terminal can be measured in picofarads, but this generally does not give the actual transfer of charge which occurs somewhere within the transformer. Two techniques are commonly used to measure partial discharge activity. NEMA Publication 107 describes a method for measuring the equivalent high-frequency voltage, usually at 1 MHz, which appears at the terminals of the transformer, while ANSI/IEEE C57.113 presents a trial-use guide to measure picocoulombs (apparent charge). The apparent charge technique is more sensitive to partial discharges occurring within the winding but also can be more susceptible to external signals. For both techniques, for power transformers the coupling capacitor can be replaced by the capacitance of the high-voltage bus, using the potential tap, as the means for coupling to the high-voltage circuit, with the effect of the capacitive impedance of the bushing being reduced by an adjustable reactor connected to the bushing tap. The voltage-measuring instrument is described in ANSI C63.2.

Basic-Impulse Insulation Level (BIL) Reduction. The need to demonstrate absence of significant partial discharges in operation is increased for higher circuit voltages where improved surge-arrester characteristics have encouraged a continuing trend toward BIL reduction. Because of progressively decreasing margins between the conventional induced test voltage and operating voltage, new standards for transformers rated 115 kV and above require a 1-h induced voltage test with continuous monitoring of partial-discharge levels to demonstrate the soundness of the insulation. During this test all parts of the insulation system must be overstressed to a degree corresponding to 150% of maximum system voltage at the high-voltage terminals (see ANSI/IEEE C57.12.00).

Partial Discharges in Transformers. This may also be detected by acoustic transducers in the oil or on the tank wall. If a sensitive transducer shows no partial discharges, any partial discharges picked up on the bushing tap originate outside the transformer. If the transducer shows corona, it can be used to locate the source of partial discharges within the transformer tank by measuring the time interval after the partial discharges voltage appears at the bushing tap until the effect appears at the transducer. Then the distance from the transducer to the source of partial discharges is 1 in for each 15 μ s of delay.

10.1.10 Radio-Influence Voltage

Excessive partial discharges may cause high-frequency voltages to appear at the terminals which can interfere with radio communication. Suitable maximum limits of voltage in compliance with Federal Communication Commission requirements have been established and are shown in NEMA Publication TR 1. For power transformers, this limits the high-frequency voltage at 1 MHz, measured at about 110% of operating voltage, to 250 μ V up to 14.4 kV operating, 650 μ V up to 34.5 kV operating, 1250 μ V up to 69 kV operating, and 5000 μ V up to 345 kV operating.

10.1.11 Testing

Standard Tests. ANSI/IEEE C57.12.00 defines routine, design, and other tests for liquid-immersed transformers. The following are listed as routine tests for transformers 501 kVA and larger:

1. Measurement of resistances of the windings
2. Measurement of turns ratio

3. Phase-relation tests: polarity, angular displacement, and phase sequence
4. No-load loss and exciting current
5. Load loss and impedance voltage
6. Low-frequency dielectric tests (applied voltage and induced voltage)
7. Leak test on the transformer tank
8. Lightning-impulse tests (full wave and chopped wave; for transformers with high-voltage windings from 115 through 765 kV)

The following are listed as design tests for transformers 501 kVA and larger (required on only one unit of a given design):

1. Temperature rise tests (could be omitted if a unit which is essentially a thermal duplicate had been previously tested)
2. Lightning-impulse tests (full wave and chopped wave; for transformers with high-voltage windings of 69 kV and below)
3. Audible sound level
4. Mechanical tests of lifting and moving devices
5. Pressure test on the transformer tank

Other tests listed in ANSI/IEEE C57.12.00 (including short-circuit tests and specialized dielectric tests) shall be made only when specified. Test procedures for all routine and design tests (and many other tests) are defined in the test code document ANSI/IEEE C57.12.90.

The regulation of a transformer may be determined by loading it according to the required conditions at rated secondary voltage and measuring the rise in secondary voltage when the load is disconnected. The rise in voltage when expressed as a percentage of the rated voltage is the percentage regulation of the transformer. This test is seldom made, because the regulation is easily calculated from the measured impedance characteristics.

Efficiency of a transformer is seldom measured directly, because the procedure is inconvenient and the efficiency can be readily calculated.

10.1.12 Oil-Preservation Systems and Detection of Faults

Oil-Preservation Systems. Although transformer oil is a highly refined product, it is not chemically pure. It is a mixture principally of hydrocarbons with other natural compounds which are not detrimental. There is some evidence that a few of these compounds are beneficial in retarding oxidation of the oil.

Although oil is not a “pure” substance, a few particular impurities are most destructive to its dielectric strength and properties. The most troublesome factors are water, oxygen, and the many combinations of compounds which are formed by the combined action of these at elevated temperatures. A great deal of study has been given to the formation of these compounds and their effects on the dielectric properties of oil, but there apparently is no clear relation between these compounds and the actual dielectric strength of the transformer insulation structure.

Oil will dissolve in true solution a very small quantity of water, about 70 ppm at 25°C and 360 ppm at 70°C. This water in true solution has relatively little effect on the dielectric strength of oil. If, however, acids are present in similar amounts, the capacity of oil to dissolve water is increased, and its dielectric strength is reduced by the dissolved water. Small amounts of water in suspension cause severe decreases in dielectric strength. The primary reason for concern over moisture in transformer oil, however, may not be for the oil itself but for the paper and pressboard which will quickly absorb it, increasing the dielectric loss and decreasing the dielectric strength as well as accelerating the aging of the paper.

It is generally recognized today that the best answer to the problem of air and water is to eliminate them and keep them out.

For this purpose, in American practice, transformer tanks are completely sealed. About three basic schemes are used in sealed transformers to permit normal expansion and contraction of oil (0.00075 per unit volume expansion per degree Celsius) as follows:

1. A gas space above the oil large enough to absorb the expansion and contraction without excessive variation in pressure. Some air may unavoidably be present in the gas space at the time of installation but soon the oxygen mostly combines with the oil without causing significant deterioration, leaving an atmosphere which is mostly nitrogen.
2. A nitrogen atmosphere above the oil maintained in a range of moderate positive pressure by a storage tank of compressed nitrogen and automatic valving. This scheme has the advantage that the entrance of air or moisture is prevented by the continuous positive internal pressure, and the disadvantage of somewhat higher cost.
3. A constant-pressure oil-preservation system consisting of an expansion tank with a flexible synthetic-rubber diaphragm floating on top of the oil. This scheme has the advantages that the oil is never in contact with the air and there is always atmospheric pressure and not a variable pressure on the oil. The disadvantage is the higher cost. A number of mechanical variations and elaborations of this general idea have been devised.

It is now generally recommended that the constant-pressure oil-preservation system of item 3 be employed on all high-voltage power transformers (345 kV and above) and on all large generator step-up transformers. This is a consequence of unfavorable experience with transformers having gas-cushion systems, which inherently operate with large quantities of the cushion gas in solution in the hot oil under load. If the oil is suddenly cooled (reduction of ambient temperature or load), the oil volume contracts and the static pressure of gas over the oil drops rapidly, allowing free gas bubbles to come out of solution throughout the insulation system. The dielectric strength of the oil and cellulose insulation system is drastically weakened when it has free gas inclusions, and this has occasionally led to electrical failure of operating transformers.

Fault Detection. Detection of internal faults in transformers at an early stage of their development is most desirable to limit the extent of damage. Two levels of seriousness of faults are recognized. Incipient (or developing) faults have not yet progressed to the point where they affect the functional capability of the transformer, but it is likely that their seriousness will increase with time if not corrected. Examples would include partial discharge sites within the insulation, intermittent low-energy sparking, overheated conductor insulation, or hot metal parts in contact with oil only. More serious or permanent internal faults affect functionality immediately and must be removed quickly before their consequences can jeopardize the safety of personnel or other equipment.

Most commonly employed means of sensing incipient faults relate to detection of gases generated at the fault site. Automatically operating gas-detection devices which can be supplied on the transformer employ any of the following principles:

1. Free gas accumulation at the cover
2. Sensing of combustible gases within a gas cushion over the oil
3. Separation of certain gases dissolved in the oil

These devices are indicators of possible internal problems. Verification of the problem should be done by gas-in-oil analysis using a gas chromatograph. In addition, periodic manual sampling of the oil for laboratory analysis should be practiced. The composition of the gas dissolved in the oil is very useful for diagnosis of the nature of an incipient fault.

Permanent internal faults can be detected by fault-pressure relays or differential relays, either of which give a signal that can be used to trip circuit breakers and remove the transformer from the system. The fault-pressure relay senses the sudden buildup of pressure produced by arc-generated gases after a fault has occurred. Unfortunately, such relays can also be operated by any other event which causes a rapid pressure change, so they cannot be set to be too sensitive. Differential relays sense that more current is flowing into the transformer than is flowing out, but relays which are

insensitive to the initial inrush of exciting current should be used. After a transformer has been disconnected as a result of relay operation, it is always desirable to get it back into service as quickly as possible. Following differential-relay operation, circuit breakers may be reclosed to check whether the fault is self-healing. The penalty for reconnection of a damaged transformer is that if the fault recurs, the damage to the transformer and possibly associated equipment will be greater. Under no circumstances should a transformer be reconnected to the system following operation of a fault-pressure relay without thorough investigation of the cause of the relay operation.

When a transformer has been taken out of service because of fault indications, the following procedure should be used:

1. If there is a gas space, take samples of the gas from the gas space for analysis to determine whether products of decomposition are present.
2. Take oil samples for extraction of dissolved gases for similar analysis.
3. Make insulation power factor, insulation resistance, and turns ratio tests to check whether their results conform to normal values.
4. Perform any other tests which seem to be indicated by the results of the first tests.
5. Check the operation and calibration of the protective relay.

10.1.13 Overcurrent Protection

Effects of Overcurrent. A transformer may be subjected to overcurrents ranging from just in excess of nameplate rating to as much as 10 or 20 times rating. Currents up to about twice rating normally result from overload conditions on the system, while higher currents are a consequence of system faults. When such overcurrents are of extended duration, they may produce either mechanical or thermal damage in a transformer, or possibly both. At current levels near the maximum design capability (worst-case through-fault), mechanical effects from electromagnetically generated forces are of primary concern. The pulsating forces tend to loosen the coils, conductors may be deformed or displaced, and insulation may be damaged. Lower levels of current principally produce thermal heating, with consequences as described later on loading practices. For all current levels, the extent of the damage is increased with time duration.

Protective Devices. Whatever the cause, magnitude, or duration of the overcurrent, it is desirable that some component of the system recognize the abnormal condition and initiate action to protect the transformer. Fuses and protective relays are two forms of protective devices in common use. A fuse consists of a fusible conducting link which will be destroyed after it is subjected to an overcurrent for some period of time, thus opening the circuit. Typically, fuses are employed to protect distribution transformers and small power transformers up to 5000 to 10,000 kVA. Traditional relays are electromagnetic devices which operate on a reduced current derived from a current transformer in the main transformer line to close or open control contacts, which can initiate the operation of a circuit breaker in the transformer line circuit. Relays are used to protect all medium and large power transformers.

Coordination. All protective devices, such as fuses and relays, have a defined operating characteristic in the current-time domain. This characteristic should be properly coordinated with the current-carrying capability of the transformer to avoid damage from prolonged overloads or through faults. Transformer capability is defined in general terms in a guide document, ANSI/IEEE C57.109, *Transformer Through Fault Current Duration Guide*. The format of the transformer capability curves is shown in Fig. 10-35. The solid curve, *A*, defines the thermal capability for all ratings, while the dashed curves, *B* (appropriate to the specific transformer impedance), define mechanical capability. For proper coordination on any power transformer, the protective-device characteristic should fall

below both the mechanical and thermal portions of the transformer capability curve. (See ANSI/ IEEE C57.10-38 for details of application.)

10.1.14 Protection Against Lightning

Impulse insulation level may be demonstrated by factory impulse-voltage tests using $1.5 \times 50\text{-}\mu\text{s}$ full waves and chopped waves. The full wave demonstrates the BIL for traveling waves coming into the station over the transmission line. The chopped wave demonstrates strength against a wave traveling along the transmission line after flashing over an insulator some distance away from the transformer. These waves do not simulate direct lightning strokes on or near the transformer terminals, which would result in the application of a steep-front wave to the transformer winding. Such strokes are usually avoided by ground wires or protecting grounded structures.

A transformer may be subjected to severe lightning voltages as a result of a direct stroke to the transformer terminal, adjacent bus, or transmission line. Less severe voltages may result from strokes on a distant part of the system or from strokes to ground near the system. Since lightning voltage may exceed the insulation strength of the transformer, protection is necessary.

Voltage-time curves are used in evaluating protection, because for short times the insulation strength changes significantly with duration of voltage. Protection is effective if the voltage-time curve of the transformer is above the voltage-time curve of the protective equipment, so that for any time duration the kilovolts insulation strength of the transformer exceeds the protective level at the same duration. The voltage-time curves of transformer insulation have considerable "turn-up," that is, for durations under $10\text{ }\mu\text{s}$ the kilovolts insulation strength is much greater. Rod gaps in air are unsuitable for protecting transformers, because they have even more turn-up than do transformers.

Surge Arresters. The modern surge arrester has very little turn-up and is an essential adjunct to the transformer whenever there is lightning exposure.

The required surge arrester rating depends on the effectiveness of the neutral grounding. The rating is expressed in percent of rated line-to-line power-frequency voltage that the arrester will withstand. Effectiveness of system grounding is described by the ratios of the zero-sequence resistance and impedance to the positive-sequence resistance and impedance. An 80% arrester is commonly used when the ratio of zero sequence to positive sequence is between 0.5 and 1.5 for resistance and between 1 and 3 for impedance. Lower ratios may permit 75% or 70% arresters. Higher ratios may require 85% or 90% arresters. Use of the 100% protective level is not economical at high voltages (Honey 1987).

Figure 10-36 shows the voltage-time curve of a 345-kV transformer, with 1050-kV BIL (reduced by two steps) compared with the voltage-time curve of a 90% metal-oxide surge arrester. Since this new type of arrester has no series gaps to spark over, the characteristic is described as a protective

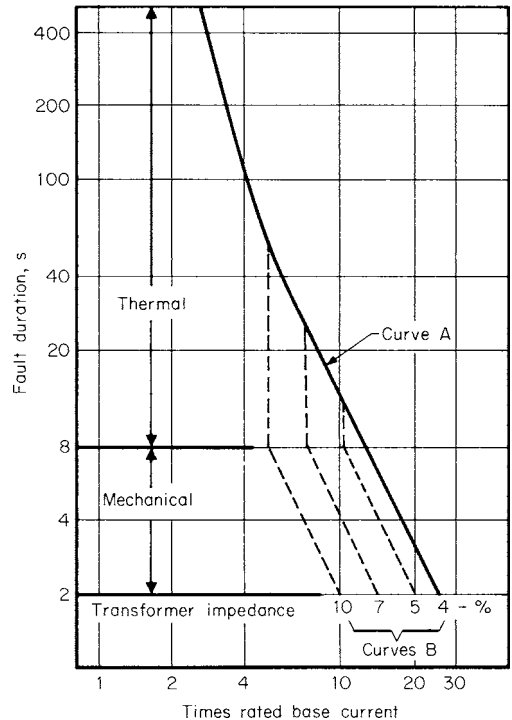


FIGURE 10-35 Transformer through-fault protection curves.

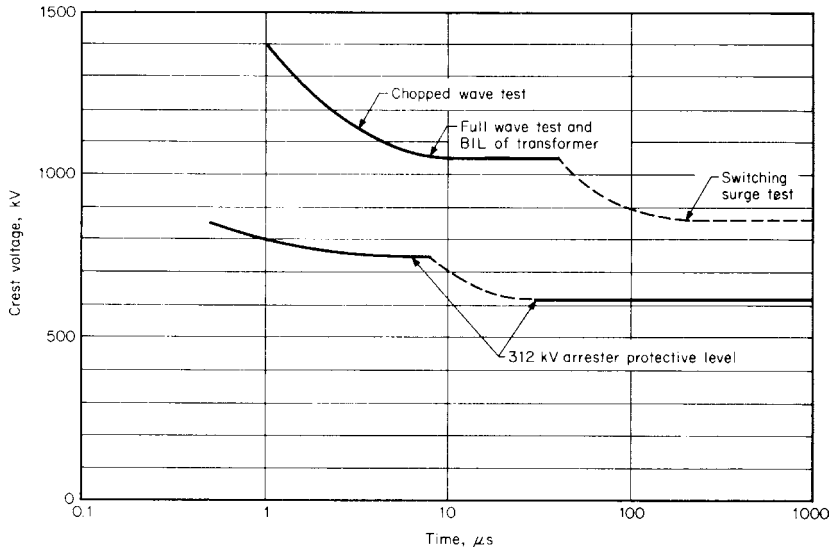


FIGURE 10-36 Surge-arrester protection margin for impulse and switching-surge conditions for a 345-kV transformer with BIL reduced two steps. The arrester curve shown is for an $8 \times 20 \mu\text{s}$ current wave of 15-kA crest.

level rather than a sparkover level. The voltage-time curve of an arrester depends on the amount of impulse current. The voltage-time curve shown in Fig. 10-36 corresponds to 15,000-A crest, which is not likely to be exceeded except by direct strokes. For best protection, the arrester should be located as close as possible to the terminals of the transformer, and the arrester ground should be connected by a short, direct conductor to the transformer tank and substation grounding system.

The steep rate of rise of lightning current as such may result from a nearby direct stroke will produce discharge voltages higher than shown in Fig. 10-36 and may damage the lightning arrester. Therefore, the substation and the first half mile of connected transmission lines should be protected against direct strokes by a suitable combination of grounded masts and ground wires (Linck 1975).

10.1.15 Installation and Maintenance

Proper installation and maintenance of power transformers is needed to assure long life in service. General requirements from ANSI C57.93 and from manufacturer's instructions are summarized below. Most power transformers have additional manufacturer's installation and maintenance instructions which should be carefully observed. These instructions, including safety practices, should be followed for the protection of workers and the transformer.

Transformers are processed tested, and inspected before shipment. Smaller transformers are shipped filled with oil and fully assembled when shipping clearances and weights permit. For most large-power transformers, the external components, such as coolers and bushings, must be removed to meet shipping dimensions. Also, the oil is removed to reduce weight, and the unit is secured in dry gas.

Inspection on Arrival. Before removal from the car, inspect for shipping damage. If damage is found, a claim should be filed with the carrier and the manufacturer should be notified.

Transformers shipped oil-filled should be inspected for evidence or leakage or entrance of moisture during shipment. If the transformer is received in damaged condition, tests should be made to check the transformer for dryness. Oil samples taken from the bottom valve should be tested for

moisture limits. Where bushings are shipped in place, insulation power-factor measurements can be used. Power factors of new transformers range from 0.2% to 0.5% at 25°C. In any case, a power-factor measurement may be helpful for comparison with test values recorded by the manufacturer prior to shipment.

Transformers shipped gas-filled are fitted with a connection to which a compound pressure/vacuum gage can be connected. The gage should have a range of +10 lb/in². A positive or negative pressure indicates that the tank is tight; a continuous zero reading indicates a probable leak. If there is a reason to question dryness, the moisture can be estimated by a dew-point measurement of the gas in the transformer. Add dry gas immediately to about 3-lb/in² (gage) pressure and check for leaks.

Dew point is sensitive to temperature changes; therefore it is essential that the insulation temperature be accurately determined. Some instruments will not provide accurate dew-point readings below 32°F. The final degree of insulation dryness should be determined by measuring the insulation power factor or insulation resistance. If the measured dew point exceeds an acceptable value, contact the manufacturer for recommended course of action.

A preliminary internal inspection is not normally required unless shipping damage is apparent. (*Caution:* Do not enter any transformer until the gas in the tank is replaced by dry air with at least 19.5% oxygen content. Exercise caution when entering a transformer and avoid introducing contamination. The time the transformer is open for inspection should not exceed 2 h, and dry air should be circulated.)

Oil sampling. Samples of oil should be taken from the bottom. An oil-sampling valve is provided at the bottom of the transformer tank for this purpose. A metal or glass thief tube can be conveniently used to obtain a bottom sample from an oil barrel. Test samples should be taken only after the oil has settled for some time, varying from 8 h for a barrel to several days for a large transformer. Cold oil is much slower in settling. In drawing samples of oil from a sampling valve, some oil should first be discarded so that the sample will come from the bottom of the container and not from the sampling pipe. Examine a sample in a clear glass container for free water, which in any quantity is readily observable. The sample container should be a large-mouthed glass bottle, 1 qt or larger, with cork or glass stopper. The bottle should be carefully cleaned and dried before being used. Bottles should be of amber color if samples are to be stored to be tested later for color or sludge-forming characteristics. Refer to ASTM 923-81 for important details of oil-sampling technique.

Testing for Oil Dielectric Strength. The testing fixture should be cleaned thoroughly to remove any particles or fibers and rinsed out with a portion of the oil to be tested. The testing fixture should be filled with oil, and both oil and fixture should be at room temperature. Allow 3 min for air bubbles to escape before applying voltage. Tests are made by two methods. ASTM D877 uses 1-in-diameter square-edge electrodes spaced 0.10 in apart and a rate of voltage rise of 3000 V/s. ASTM D 1816 uses special radiused-surface electrodes spaced 0.04 in apart, with continuous oil circulation, and a rate of voltage rise of 500 V/s. The latter test is more sensitive to slight moisture or particulate contamination. In either case, the average voltage for five breakdowns is taken as the dielectric strength of the oil. Strength of new oil should exceed the minimum value for good oil as shown in Table 10-4. (See also ANSI/IEEE C57.106.)

TABLE 10-4 Dielectric Strength of Oil

kV average dielectric strength by ASTM D877-82	kV average dielectric strength by ASTM D1816-82	Condition of oil
30 or over	29 or over	Good
26 to 29	23 to 28	Usable
Under 26	Under 23	Poor

Filtering to Increase Dielectric Strength. If the oil tests below “good,” it should be filtered to remove impurities and moisture. It is best to discharge filtered oil into a clean, dry tank and avoid mixing with unfiltered oil. If the filtered oil must be discharged back into the transformer tank, the oil should be withdrawn from the bottom filter-press valve and, after filtering, returned through the top filter-press valve. Oil should not be filtered while the transformer is energized, because the dielectric strength may be temporarily reduced by aeration. If no facilities are available for making dielectric tests, send a sample to the manufacturer marked with the serial number of the transformer.

Drying the Core and Coils. This should be necessary only if an accident occurs during shipping, storage, or service. (Refer also to ANSI/IEEE C57.12.11 and C57.12.12.)

If possible, determine the extent of the moisture and manner in which it entered the tank. The manufacturer should be contacted for recommendations concerning additional checks and strips for drying out the transformer. If drying is necessary, one or more of the following methods may be used, depending on the facilities available:

1. Heat and vacuum
2. Vacuum only
3. Heat in oil
4. Heat in air

A low value of residual moisture can be attained most rapidly by method 1. Method 2 is effective but requires longer time and better vacuum equipment. Method 3 is very slow and not as effective as the vacuum method. Method 4 is recommended only for smaller, low-voltage transformers.

Method 1: Heat and Vacuum. The following procedures may be used to elevate the temperature of the core and windings prior to the vacuum process:

1. Using external heaters and pump equipment, spray hot oil through the cover of the transformer. Maintain a vacuum of 10 torr or less on the transformer during the oil spraying operation in order to prevent oxidation of the oil and to aid in the removal of gas from the insulation. Pump the oil from the bottom of the transformer through filters, through the heat exchanger, and back to the cover of the transformer. Use the minimum amount of oil necessary to establish circulation. Degassing-dehumidifying equipment may be used if the equipment is available. The oil temperature entering the top of the transformer should be between 50°C (122°F) and 75°C (167°F). The temperature of the core and coils will be elevated to equilibrium conditions when the output oil temperature becomes constant, and the temperature of the core and coils will be near the temperature of the output oil.
2. Heat may also be generated by circulating current through the windings. This requires a controlled source of power connected to either winding, with the other winding short-circuited. For this method, the transformer should be filled to normal level. Connect the vacuum pump to a suitable valve above the oil level. The temperature of the windings should not exceed 95°C and the oil 85°C. Initial currents up to full-rated current may be used, then reduced as the temperature approaches the desired value. The voltage required to circulate this current will depend on the impedance of the transformer, which can be obtained from the instruction plate. After the desired winding and oil temperatures have been reached, disconnect the power supply and drain the oil from the transformer tank. When the oil has been drained from the tank, close the valves and start the vacuum pump. Continue pulling vacuum on the transformer until the water extraction stops.

Method 2: High Vacuum. This method requires the use of a suitable vacuum pump, capable of pumping down to an absolute pressure of 0.05 mmHg (6.67 Pa) or lower, and a refrigerated vapor trap to collect the water. No additional heat is required if an adequate vacuum pump is used.

Drain the oil from the transformer, filling the tank with dry nitrogen as the oil is drained. Remove heat exchangers and other external pipe connections and seal these openings, preferably

with blanking plates. Connect the vapor trap and vacuum pump to a suitable pipe connection on the tank. Seal the tank and pressure test for leaks. After ensuring that all leaks have been eliminated, start the vacuum pump. Water extraction from the insulation will begin when the residual vapor pressure in the tank is reduced below the vapor pressure of water in the insulation. Drying may be continued as long as moisture is being extracted or may be terminated when the residual moisture content of the insulation has been reduced to the desired level as determined from a moisture equilibrium chart.

Method 3: Heat in Oil. This method is slow and limited to smaller, low-voltage transformers. Also, method 3 may be used for transformer tanks not designed for full vacuum. This method requires the use of a suitable oil filter with either a vacuum-drier-type or blotter press, plus a heater which will enable hot oil at a temperature of approximately 85°C to be circulated in the transformer tank until positive indication of drying out of the windings has been obtained. The transformer should be filled with oil to cover the core and windings and the oil circulated through either the filter-press valve and drain valve or through top and bottom radiator valves. Wherever possible, to reduce heat losses due to radiation, prevent the oil from circulating through the coolers. Blanket the outside of the transformer tank to reduce to a minimum the time of drying out and the amount of heating required to keep the oil temperature constant.

With this method the moisture is removed through the oil filter. If a blotter-press filter is used, the rate of water extraction will depend on the degree of saturation of the filter papers. Filter papers must be extremely dry and papers must be changed frequently if this method is to be effective. The rate of transfer of moisture increases with temperature; hence it is desirable to operate at the highest temperature which will not cause deterioration of the oil.

Method 4: Hot-Air Drying. This is limited to small low-voltage transformers and where clean dry air is available. With the transformer assembled in its tank, the tank should be blanketed in order to reduce to a minimum the amount of heating required, and also to keep the interior of the tank at a uniform temperature to prevent condensation in the tank.

Dry air should be forced by a fan over the heating elements, then through an opening at the base of the tank to pass over and through the coils before exhausting through an opening in the cover. Baffles should be placed between the hot-air inlet and the windings to prevent the flow of hot air from being concentrated on one small portion of the windings.

Time Required for Drying. This can range from 72 h to 3 weeks depending on the size and condition of the transformer and the method of drying. In general, the use of a high vacuum and a cold trap is faster and more efficient than heat alone.

Insulation Resistance. This will indicate the degree of dryness only when the transformer is dried without oil. If the initial insulation resistance is measured at room temperature, it may be high, although the insulation is not dry, but as the transformer is heated up, it will drop rapidly.

As the drying proceeds at a constant temperature, the insulation resistance will generally increase gradually until toward the end of the drying period, when it increases quite rapidly and then levels off at a high value. The drying should continue until the resistance is constant for a period of 12 h.

Insulation Power-Factor Reading. These readings (at 60 Hz) will indicate the degree of dryness. The power factor will first increase as the temperature increases and then will gradually decrease as drying progresses. Drying should continue until the power factor is constant for a period of 12 h. If power factor is measured on transformers dried in oil by the short-circuit method, the power factor should be used to supplement oil tests as a measure of dryness.

Filling without Vacuum. (Note: This method should be practiced only on low-voltage transformers. Check manufacturer's recommendations.) Use extreme care to keep moisture out of the core and coils. The tank should not be opened to the atmosphere until the core and coils are under oil, unless vacuum filling is available. The oil shipping tank or oil drums should not be opened until their temperature is the same as or higher than that of the surrounding air and the transformer is in place and

ready to receive the oil. Metal or synthetic rubber hose should be used for filling, because transformer oil is contaminated by natural rubber. Oil should never be added to a transformer without passing through a filter press.

Static charges can be developed when transformer oil flows in pipes, hoses, or tanks. Oil leaving a filter press may be charged to over 50,000 V. To accelerate dissipation of the charge in the oil, ground the filter press, the tank, and all bushings or winding leads during oil flow into any tank. Conduction through oil is slow; therefore it is desirable to maintain these grounds for at least 1 h after the oil flow has ended.

Avoid explosive gas mixtures in any container into which oil is flowing. Arcs can occur along the surface of the charged oil even though all metal is grounded.

Filling with Vacuum. The vacuum line should be connected to a tapped opening on a cover-mounted shipping plate or to a valve near the top of the tank. An opening of 2 in minimum is recommended. The oil line can be connected to a suitable opening on a cover-mounted shipping plate or the top filter-press valve. The oil line should always be connected at the top of the tank so that the oil can be deaerated as it enters.

Transformers with operating voltage less than 161 kV and with core and coils not exposed to the atmosphere should be filled under vacuum better than 25 mmHg absolute pressure. The vacuum should be held 4 h before filling and continued during filling until the core and coils are covered. The vacuum can then be removed for installation of bushings and the remaining oil added without vacuum. Transformers with an operating voltage of 161 kV and above or transformers with core and coils exposed to the atmosphere should be completely filled under a vacuum better than 2 mmHg absolute pressure. A 2-mm vacuum should be held until the tank is filled to the 25°C level.

The filling rate should be under 1500 gal/h to facilitate evacuation and complete oil filling of all air pockets and voids. It is also recommended that the core and coil temperature be above 10°C to prevent “frost” formation.

Energization. When the voltage is first applied, it should, if possible, be brought up slowly to its full value so that any wrong connection or other trouble will be discovered before damage results. After full voltage has been applied successfully, the transformer should preferably be operated for a short period without load.

When the transformer is first energized it should be kept under close observation for the first 8 h. Check and record the oil temperature, the winding temperature, the tank pressure, and the ambient temperature. Watch particularly for any sudden changes. After 7 days of operation, check for oil leaks and for abnormally high usage of nitrogen if the transformer is equipped with Inertaire. Stop all oil and gas leaks. The observation should continue on a daily schedule for 7 days and then weekly for the first month of operation. An oil sample should be taken during the first month of operation for gas-in oil analysis. This analysis should be repeated annually. Heat exchangers, tap changer, pumps, fans, etc., should be serviced per manufacturer’s instructions.

Internal Inspection of In-service Transformers. This is not necessary unless there is a specific indication of a problem. Oil analysis is a good method to discover potential problems. Sludging of the oil, low dielectric strength, moisture in the oil, or the presence of combustible gases are conditions that may merit an internal inspection of the transformer.

Generation of combustible gas usually indicates internal trouble (not necessarily serious). Analysis of the gas sometimes helps to identify the source. If collection of combustible gas continues without discoverable cause, partial discharge voltage measurement may establish whether or not there is an internal fault.

Severe system disturbances, incidence of through-fault, or a circuit-breaker operation would also be reason for an internal inspection of a transformer.

Operating without Cooling. A liquid-cooled transformer should not be run continuously, even at no load, without the cooling liquid. In an emergency, forced-oil air-cooled transformers may be operated without fans and pumps (1) at rated load for approximately 1 h, starting at full-load temperature rise,

(2) at rated load for approximately 2 h, starting cold (at ambient temperature), (3) at rated voltage and no load for approximately 6 h, starting at full-load temperature rise, and (4) at rated voltage and no load for approximately 12 h, starting cold.

When only a portion of the cooling equipment is operating, the transformer may be operated at reduced load approximately as indicated in Table 10-5.

TABLE 10-5 Operation with Limited Cooling Equipment

Percent of cooling equipment in operation	Percent of rated load that may be carried
33	50
40	60
50	70
80	90

10.1.16 Loading Practice

The *temperature limitation of loading* must be considered. Ordinarily, the kVA that a transformer should carry is limited by the effect of reactance on regulation or by the effect of load loss on system economy. At times, it is desirable to ignore these factors and increase the kVA load until the effect of temperature on insulation life is the limiting factor. High temperature decreases the mechanical strength and increases the brittleness of fibrous insulation, making transformer failure increasingly likely, even though the dielectric strength of the insulation material may not be seriously decreased. Overloading of transformers should be limited by reasonable consideration of the effect on insulation life and the probable effect on transformer life.

The *insulation life of a transformer* is defined as the time required for the mechanical strength of the insulation material to lose a specified fraction of its initial value. Loss of 50% of the tensile strength is the usual basis for evaluating conductor insulation for power transformers. (Note: A transformer may continue to perform beyond the predicted life if it is not disturbed by short-circuit forces, etc. This is because at the mechanical end point, the disintegration of the fibers is not total as shown by degree of polymerization measurements, the true indicator of paper insulation integrity.)

The *aging of insulation* is a chemical process that occurs more rapidly at higher temperatures according to the Arrhenius reaction-rate theory, as expressed in

$$\log h = \frac{K_1}{C + 273} + K_2 \quad (10-63)$$

where C = temperature in degrees Celsius of insulation, K_1 , K_2 = constants determined by test, and h = hours of life. Use of this equation permits results of relatively short duration tests at relatively high temperature to be extrapolated to indicate probable insulation life at moderate temperatures. ANSI/IEEE C57.92-1981 contains loading recommendations for power transformers up to 100 MVA with 55°C and 65°C average winding-rise insulation systems based on extrapolated life tests. Figure 10-37 shows the corresponding curves of rate of loss of life as a function of temperature as defined in this document. The constants in Eq. (10-63) are

$$55^\circ\text{C rise} \quad K_1 = 6972.15 \quad K_2 = -14.133$$

$$65^\circ\text{C rise} \quad K_1 = 6972.15 \quad K_2 = -13.391$$

ANSI/IEEE C57.91 provides similar loading recommendations for distribution transformers, including the following values for the constants in Eq. (10-63):

$$55^\circ\text{C rise} \quad K_1 = 6328.8 \quad K_2 = -11.968$$

$$65^\circ\text{C rise} \quad K_1 = 6328.8 \quad K_2 = -11.269$$

Accepted methods for functional life evaluation have been established for both distribution transformers and for power transformers.

To determine the aging of the insulation resulting from a specific daily load cycle (1) establish an approximately equivalent stepped load cycle, (2) calculate the resulting curve of hot-spot

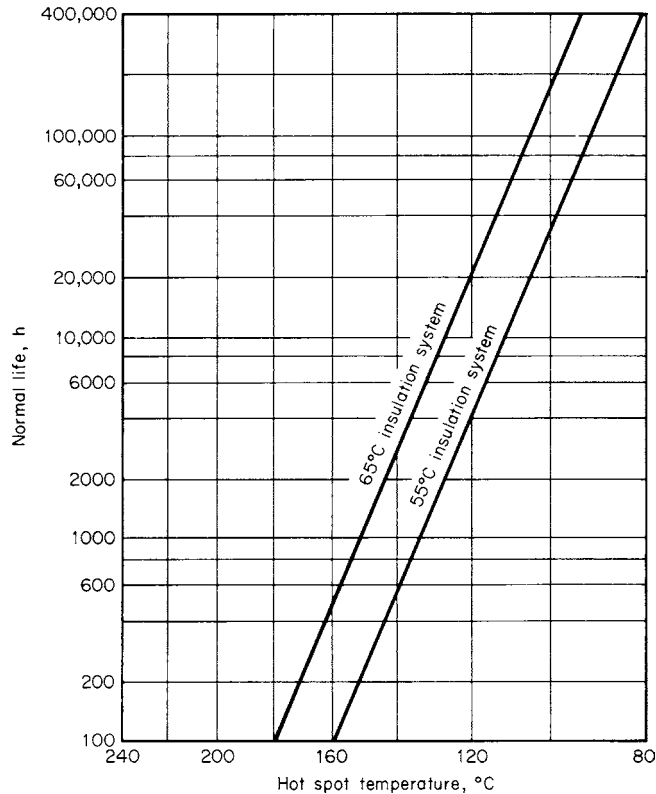


FIGURE 10-37 Loss of life as a function of temperature for power transformers up to 100 MVA under loading conditions of ANSI/IEEE C57.92.

temperature, (3) replace the hot-spot temperature curve by an approximately equivalent stepped curve, (4) calculate the percent aging for each step from the applicable curve of Fig. 10-37, and (5) add the aging for all the steps in the daily cycle. The result is the fraction of insulation life used up each day. The reciprocal is the number of days of total insulation life if the same load cycle repeats every day.

For example, consider a transformer with a daily load cycle of 4 h at 140% load and 20 h at 80% load in 30°C ambient. The hot-spot temperature curve shown in Fig. 10-23 is reproduced in Fig. 10-38, together with an equivalent stepped curve. The calculation of loss of life per day is shown in Table 10-6.

The normal life at every temperature can be determined from Fig. 10-37 or from Eq. (10-63) for the 65°C rise insulation system. The fraction of the life consumed during each time step can then be calculated and summed for all of the time steps in the 24-h period. In this case, 0.09% of the life is consumed in one day, so the total life would be 1111 days or about 3 years if this load cycle were continued. For comparison, a transformer with a 65°C average winding-rise insulation system (80°C hot-spot rise) operating in a 30°C ambient would have a hot-spot temperature of 110°C and a normal life of 65,000 hours or 7.4 years. The shortening of the insulation life from 7.4 years to 3 years is a measure of the severity of the load cycle. The actual transformer life may, of course, be shorter or longer, depending on exposure to overvoltage, overcurrent, shock, contamination, fault conditions, etc.

Loading-capability tables for normal consumption of life and for moderate sacrifice of life are documented in ANSI/IEEE C57.92 for power transformers. Information is provided for situations

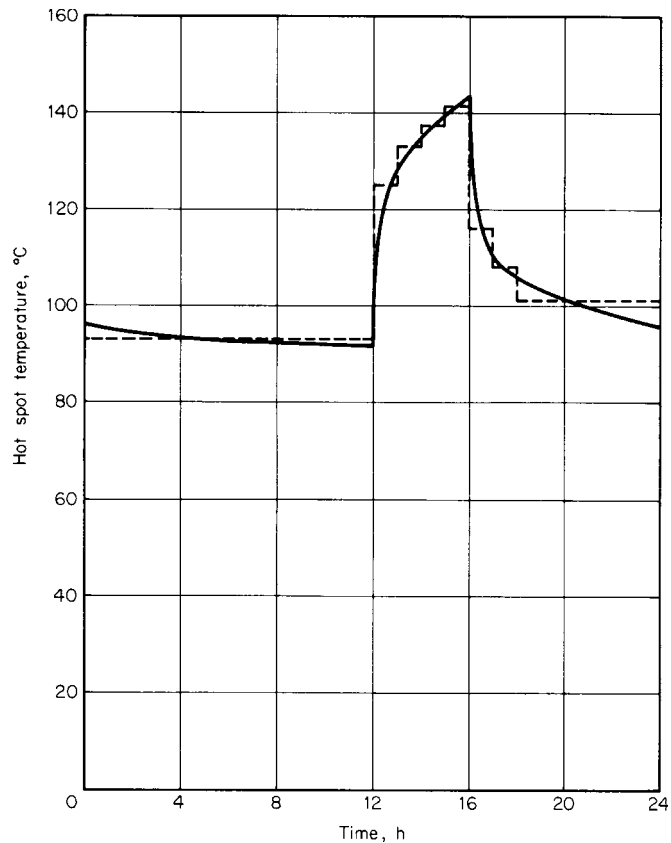


FIGURE 10-38 Equivalent stepped curve of hot-spot temperature for loss-of-life calculations of a daily load curve.

involving different ambient temperatures, different peak-load durations, and different loads prior to the peak for an assumed set of representative transformer characteristics.

Ambient temperature affects load capacity by an amount dependent on the type of cooling, as shown in Table 10-7.

TABLE 10-6 Calculation of Loss of Life per Day on Daily Load Cycle

Duration of step, h	Temperature of hot spot, °C	Life, h, at temperature	% loss of life on step
12	93	455,600	0.003
1	125	13,396	0.007
1	133	6,050	0.017
1	137	4,114	0.024
1	141	2,818	0.035
1	116	34,062	0.003
1	108	81,023	0.001
6	101	178,284	0.003
			0.093

TABLE 10-7 Effect of Ambient Temperature on kVA Capacity

Type of cooling	% of rated kVA decrease in capacity for each °C increase over 30°C air or 25°C water	% of rated kVA increase in capacity for each °C decrease under 30°C air or 25°C water
Self-cooled*	1.5	1.0
Water-cooled†	1.5	1.0
Forced-air-cooled*	1.0	0.75
Forced-oil-cooled*	1.0	0.75

*From 0 to 50°C air temperature.

†Up to 35°C water temperature.

For ambient temperature of air-cooled transformers, use the average value over a 24-h period or 10°C under the maximum temperature during the 24-h period, whichever is higher. For ingoing water temperature, use the average value over a 24-h period or 5°C under the maximum temperature during the 24-h period, whichever is higher.

Limitations. The temperature of the top oil should never exceed 110°C for power transformers with a 55°C average winding-rise insulation system or 110°C for those with a 65°C average winding-rise insulation system. The consequence of exceeding these limits could be oil overflow or excessive pressure. The winding hot spot should not exceed 150°C for the 55°C average winding-rise insulation system or 180°C for the 65°C average winding-rise insulation system. These limitations are based principally on a concern for rates of insulation aging, but it should be noted that free bubbles may be evolved at hot-spot temperatures above 140°C, with consequent weakening of dielectric strength. The peak short-duration loading should never exceed 200% of rating, except for transformers rated over 100 MVA a limit of 150% of rating is recommended (IEEE Standard 756). This reflects a concern for stray flux heating in large units.

10.1.17 Loss Evaluation

Loss evaluation is a procedure by which the buyer and seller achieve an economic balance in adding material to the transformer design to get lower losses. It is achieved by establishing a value in dollars per kilowatt for load loss and a similar value for no-load loss.

An incremental investment in capacity is required to generate power to supply loss and bring it to the transformer. In addition, there is a continuing expense for fuel to supply the lost power. The continuing expense is converted to present worth and added to the incremental investment to give the total present worth of the loss. This present worth of a kilowatt of loss is naturally higher for the no-load loss, which is continuous, than it is for the load loss, and the value is higher the farther the transformer is from the generator; the values will of course depend on the accounting rules and procedures in force at the particular location.

The following equations are commonly used to establish loss evaluations:

$$V_L = S + \frac{8760EF_L}{R} \quad (10-64)$$

$$V_N = S + \frac{8760EF_N}{R} \quad (10-65)$$

where E = dollars per kilowatthour cost of energy (this can conceivably be very low for a hydro station but can range up to 0.02 or more for fuel-fired stations, depending on fuel cost, and, of course, the figure will be even higher at locations remote from the generating station), F_L = ratio of average load loss to rated load loss, F_N = ratio of average no-load loss to rated no-load loss (1.00 for continuous operation), R = per unit (%/100) annual carrying charge on system investment (covers insurance, taxes, depreciation, and return on investment), S = dollars per kilowatt system investment

(200 and up, depending on the system investment out to the transformer location), V_L = dollars per kilowatt evaluation of rated load loss, and V_N = dollars per kilowatt evaluation of rated no-load loss.

Since the load losses of a transformer vary as the square of the load, it is important to state the MVA rating at which the load losses will be evaluated. Since it is common practice of most transformer manufacturers to optimize the design of the transformer at its self-cooled rating, the dollar value of losses for the load loss should be specified at the self-cooled rating. If the dollar value of losses for the load loss is specified at some load other than the self-cooled rating, it can be adjusted to the self-cooled rating by multiplying the dollar value by the square of the ratio of the load at which the losses will be evaluated and the self-cooled rating.

It is also important that the transformer manufacturer knows if the buyer is using the present-worth, the levelized annual cost, or the capitalized cost method of evaluation. If the present worth method is being used, the present-worth multiplier should be stated; if the levelized annual cost method is being used, the carrying charge should be stated so the manufacturer, in either case, knows how the dollar values of losses equate to the first cost of the transformer.

Loss evaluation is an important factor in purchasing new transformers, as in many cases the evaluation of the total loss equals or exceeds the price of the transformer.

10.1.18 Autotransformers

Part of an autotransformer winding is common to both primary and secondary circuits. The common portion is called the common winding, and the remainder is called the series winding. The high-voltage terminal is called the series terminal, and the low-voltage terminal is called the common terminal. Part of the power passes from one winding to the other by transformation, and the rest passes directly through without transformation. Figure 10-39 shows an autotransformer compared with an equivalent two-winding transformer. Both have the same ratio of secondary voltage to primary voltage, T , and both have the power output. The fraction $1 - T$ of the power is transformed, and the fraction T passes through without transformation. The fraction $1 - T$, called the "co-ratio," is a measure of the required size of the core and coils as compared with a two-winding transformer. In addition, the losses and reactance are reduced in approximately the same ratio. For a low value of $1 - T$ the economy of an autotransformer compared with a transformer is attractive.

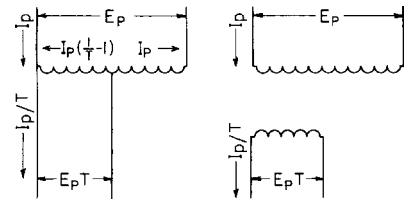


FIGURE 10-39 Comparison of an autotransformer with a two-winding transformer.

The following special characteristics of autotransformers may need consideration: A metallic connection exists between the primary and secondary circuits; this is generally of little consequence with low-voltage circuits, but with high-voltage systems the neutral point must be grounded for safe operation.

The impedance of an autotransformer is normally lower than that of the equivalent two-winding transformer, and the short-circuit current is higher.

Taps near the neutral are relatively ineffective, because turns tapped out at the neutral come out of both circuits and increase core flux density without greatly changing the voltage ratio. The high-voltage rating is more effectively adjusted by taps in the series winding. The low-voltage rating is more effectively adjusted by tapping turns out of the common winding while turns are added to the series winding or by placing the tapping winding in the low-voltage line.

Inversion of the neutral may occur under abnormal conditions in Y-connected autotransformers with ungrounded neutrals. If the voltage on a series terminal is lower than the voltage on the corresponding common terminal, high voltage tends to appear on the neutral. Inversion of the neutral can occur on power-frequency voltage or on transient voltage. Grounding the autotransformer neutral, use of a delta tertiary, and use of three-leg 3-phase cores all help to prevent inversion of the neutral.

Autotransformers are most commonly used to connect two transmission systems at different voltages, frequently with a delta tertiary winding. It is also possible to apply an autotransformer as a generator step-up transformer when it is desired to feed two different transmission systems. In this case

the delta tertiary winding is a full-capacity winding connected to the generator, and the two transmission systems are connected to the autotransformer windings. Advantages of the autotransformer when compared to a normal transformer include lower impedance, lower losses, better regulation, smaller size, and lighter weight.

10.1.19 Distribution Transformers

Distribution transformers are generally considered as transformers of 500 kVA, and smaller 67,000 V and below, both single-phase and 3-phase. Older installations are primarily pole-/platform-mounted units. Newer installations are frequently pad-mounted units. Typical applications are for supplying power to farms, residences, public buildings or stores, workshops, and shopping centers.

Distribution transformers have been standardized as to high- and low-voltage ratings, taps, type of bushings, size and type of terminals, mounting arrangements, nameplates, accessories, and a number of mechanical features, so that a good degree of interchangeability results for transformers in a certain kVA range of a given voltage rating. They are now normally designed for 65°C rise.

The most popular primary voltages are 12,470Y/7200, 13,200Y/7620, and 12,000 V delta.

Many of the 2400- and 4800-V primary systems have been converted to 7200 and 7620 V. There is also increasing use of higher-voltage distribution systems such as 24,900Y/14,400 and 34,500Y/19,900 V. Secondary voltage for pole-type units is usually 120/240 or 240/480, 240/120 on single-phase pad-mount units and 208Y/120 on 3-phase units.

Magnetic cores, in general, are composed of cold-rolled silicon steel strip. They take various forms, all designed so that the magnetic flux will pass through the sheet in the direction of the rolling in order to secure the maximum benefit of the superior magnetic quality of this material. For an appreciable portion of the 24-h day, the typical distribution transformer (particularly the pole-mounted 5- to 167-kVA range) is lightly loaded. Because of this, the loss in the core is a significant portion of the total daily loss. Cores for these units are therefore designed for low exciting current and for relatively low core loss to minimize the operating cost. Low-loss cold-rolled silicon strip has contributed materially to reduced losses, weights, and dimensions. New amorphous steel alloys are providing additional opportunities to reduce the units operating costs.

Coils are usually wound in a concentric layer arrangement, with cooling ducts distributed periodically between the layers to maintain reasonable differentials between oil temperature and the average coil and hot-spot temperatures. As a matter of practical operating procedure, distribution transformers are subjected to considerable numbers of overloads for short time periods. Hot-spot temperatures must be limited on these overload excursions if the transformer is to have a long insulation life. It is now general practice to employ thermally upgraded materials in the insulation system to improve aging characteristics. Increased mechanical strength is achieved by using a special intermittent coating of a heat-reactive adhesive on the layer insulation to bond the coil into a rigid mass during the drying process. Heat and vacuum drying plus vacuum oil filling imparts good dielectric strength to the windings.

Aluminum and copper conductors are both used in the coils of distribution transformers. The decision to use one material over another is based on the required loss performance levels for individual utilities. Aluminum conductor is widely used in the secondary windings, where full-width aluminum strip is employed. Such coils are also mechanically stronger.

To cool the unit, the radiating surface of the tank itself suffices in the smaller ratings. In the larger ratings, auxiliary cooling is provided by the addition of fins or tubes. By these means, the height, size, and weight are held to desirable minimums. Special attention is given to sealing the transformers from the atmosphere. Likewise, careful attention is given to the external finish and fittings to assure reliable service for many years of exposure to the elements. External connectors are good for either aluminum or copper conductors.

The conventional pole type (Fig. 10-40) consists of core and coils securely mounted in an oil-filled tank, with the necessary terminals brought out through their appropriate bushings. The high-voltage bushings may be two in number, but one bushing plus a ground terminal on the tank wall connected to the ground end of the high-voltage winding for use on multiple-grounded circuits is the most common usage. The conventional type includes just the basic transformer structure without any

protective equipment. The desired overvoltage, overload, and short-circuit protection is obtained by using lightning arresters and primary fuse cutouts separately mounted on the pole or crossarm closely adjacent to the transformer. The primary fuse cutout provides a means of visually detecting blown fuses on the system primary and also serves to remove the transformer from the high-voltage line, either manually when desired or automatically in the event of an internal coil failure.

The self-protected transformer (Fig. 10-41*a*) has an internally mounted, thermally controlled secondary circuit breaker for overload and short-circuit protection; an internally mounted protective link in series with the high-voltage winding to disconnect the transformer from the line in the event of an internal coil failure; and a lightning arrester or arresters integrally mounted on the outside of the tank for overvoltage protection. On most of these transformers, except some 5-kVA ratings, the circuit breaker operates a signal light when a predetermined winding temperature has been reached, as a warning before tripping. If the signal is unheeded and the breaker trips, the breaker may be reset and the load restored by an external handle. Usually, this can be accomplished with the normal breaker setting. If, however, the load has been a long-sustained one which has allowed the oil to reach a high temperature, the breaker may soon



FIGURE 10-40 Conventional pole-type distribution transformer.



FIGURE 10-41 (a) Self-protected pole-type distribution transformer; (b) RUS design self-protected pole-type distribution transformer for rural electric cooperatives.

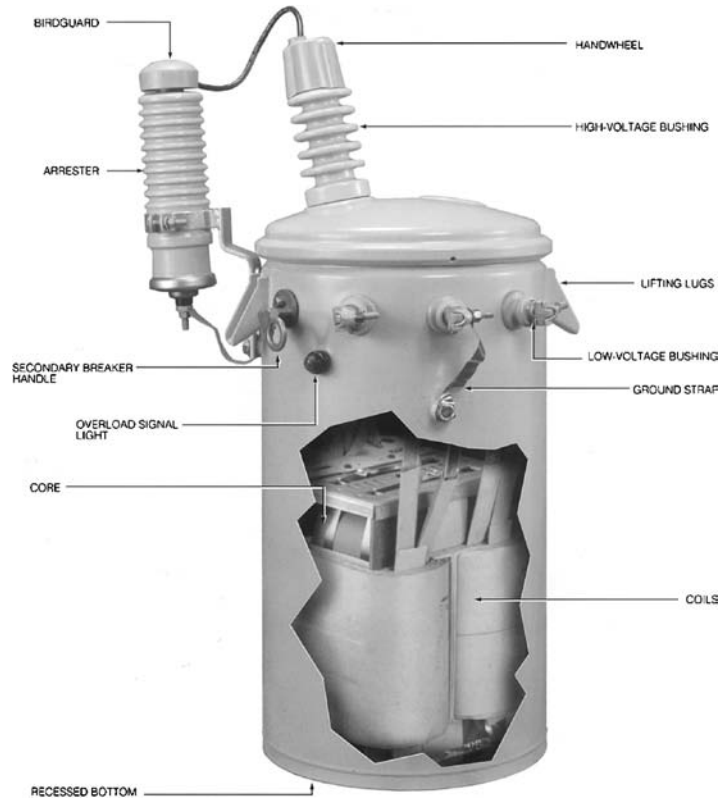


FIGURE 10-42 Cutaway view of a completely self-protected pole-type distribution transformer.

trip again, or it may be impossible to reset so that it will remain closed. In such cases, the trip temperature may be set up by an auxiliary external control handle to allow reclosing of the breaker for the emergency until a larger transformer can be installed.

Figure 10-41*b* shows the rural cooperative style. Figure 10-42 shows a cutaway view of the self-protected design.

3-Phase self-protected transformers are similar to the single-phase units except that a 3-pole circuit breaker is used. The breaker is arranged to open all 3 poles in case of a serious overload or fault on one of the phases (Fig. 10-43).

The self-protected transformer for secondary banking is another variation. Such transformers are provided with the two secondary breakers to sectionalize the low-voltage circuits, confining the outage to just the faulted or overloaded section, leaving the entire transformer capacity available for supplying the remaining sections. These are also made for single- and 3-phase units.

“Station-type” distribution transformers are normally rated 250, 333, or 500 kVA. A “pole/station type” distribution transformer is used. For distribution to low-voltage ac networks in areas of high-load density, network transformers are available in even higher ratings.

Losses and Characteristics. For the pole-type ratings 100 kVA and smaller, full-load efficiencies range from 97% to 99%, and impedance is generally less than 2%.

Recent trends have been toward further reduction of no-load loss, exciting current, and sound level. Replacement of much of the round and rectangular conductors in the secondary winding with full-width strip has resulted in more compact windings with greatly increased mechanical strength.

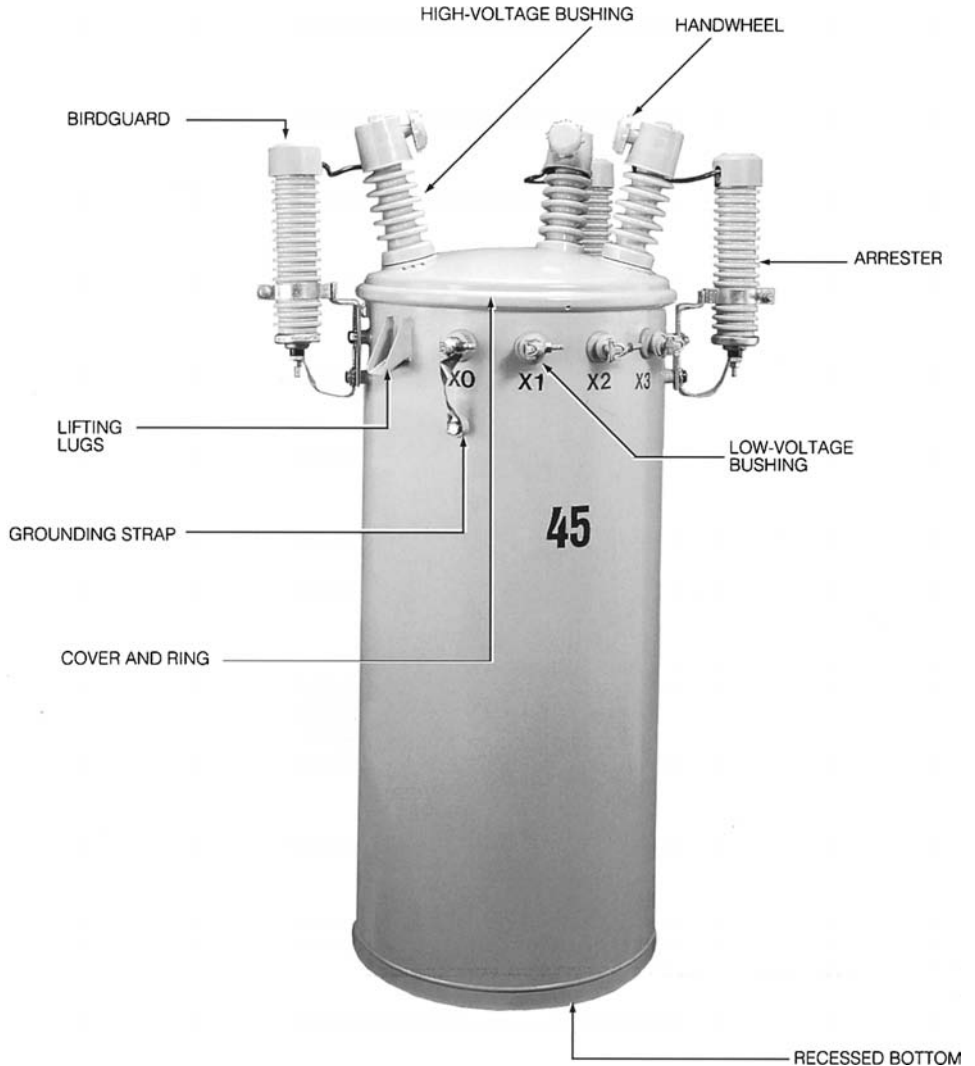


FIGURE 10-43 Three-phase, pole-type distribution transformer.

More effective utilization of distribution transformer investment is being made possible through transformer-load-management programs.

Transformers for Underground Distribution Systems. Since more distribution circuits are being put underground, transformers have been especially developed to be used with such systems. The most widely used type is the pad-mounted transformer, so called because it is designed to mount on a concrete-surface slab or pad. A typical transformer is shown in Fig. 10-44. The essential differences from the pole-type transformers are only in the mechanical arrangement:

1. A rectangular case in two compartments.
2. One compartment containing the conventional core-coil assembly.

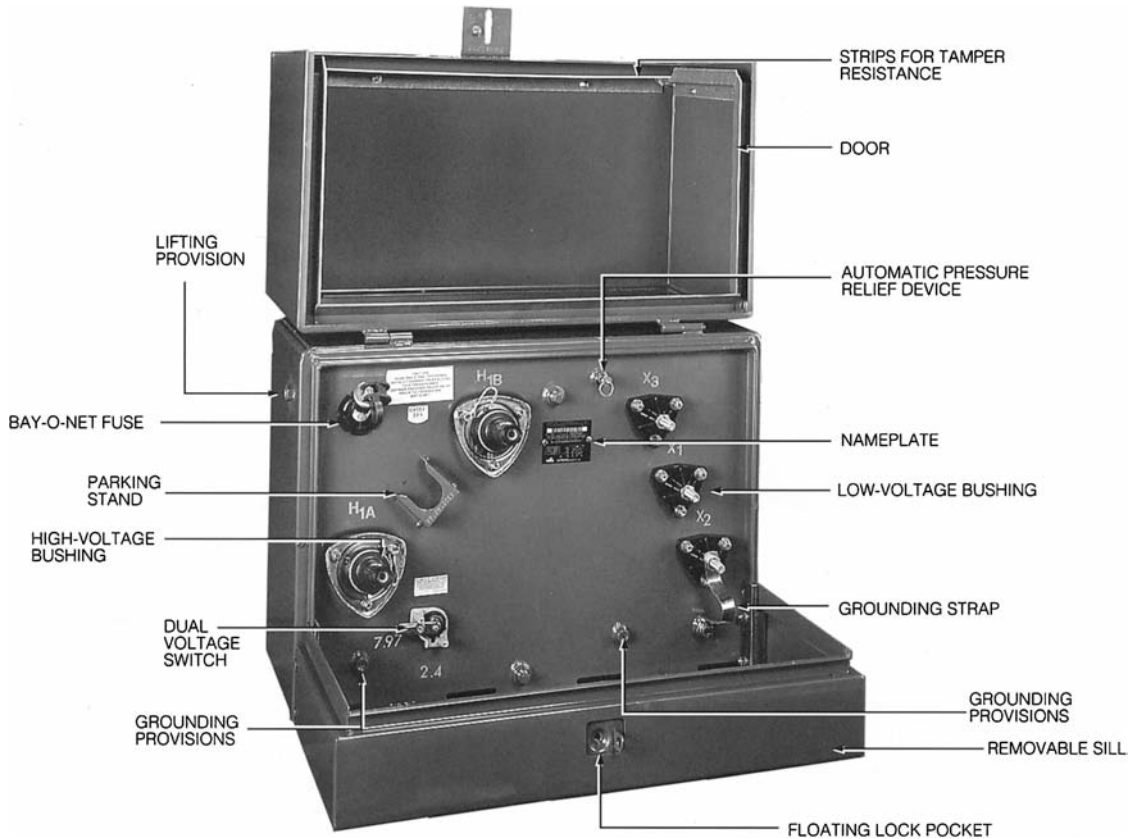


FIGURE 10-44 Single-phase, pad-mounted transformer.

3. A second compartment for cable termination and connection. The primary cable conductors are connected by plug-in connectors suitable for load make or break. The secondary conductors usually bolt to bushing terminals.
4. Fuses of various sorts provided for by a fuse holder placed in a well in the side of the tank so that the fuse holder can be drawn out.

Another transformer arrangement is designed to operate in a subterranean vault. This looks more like a pole-type transformer but is usually made with a corrosion-resistant steel tank, plug-in primary connectors, and a temperature rise in free air of only 55°C to allow for the higher ambient temperature which may actually exist in a vault.

Ferroresonance in Distribution Transformers. *Ferroresonance* is the name given to the phenomenon where the exciting reactance of the transformer can become nearly equal to the capacitive reactance of the line to ground, forming a resonant circuit. Such a resonant circuit can distort the normal line impedance to ground so that one line of a 3-phase circuit can rise to a destructive voltage.

Such a phenomenon practically never occurs in a normal circuit configuration with the transformers loaded, but it can exist under a combination of the following circumstances which usually occur only during switching of a 3-phase bank or blowing of a fuse in one line:

1. System neutral grounded, ungrounded transformer neutral
2. No load on the transformer
3. Relatively large capacitance line-to-ground such as may exist in cable circuits (underground distribution) or very long overhead lines (although ferroresonance can be and has been corrected by adding still more capacitance which presumably throws the combination out of resonance again)

Although ferroresonance has been studied at some length, it still does not seem possible to reliably predict its occurrence. Experience indicates that it is possible to prevent ferroresonance during switching on a transformer bank if all three transformers are resistance-loaded to 15% or more of their rating, or if special switches are used to assure that the three lines close simultaneously.

10.1.20 Furnace Transformers

Furnace transformers supply power to electric furnaces of the induction, resistance, open-arc, and submerged-arc types. The secondary voltage are low, occasionally less than 100 V, but generally several hundred volts. Sizes range from a few kVA to over 150 MVA, with secondary currents over 100,000 A. High currents are obtained by parallel connection of many winding sections. Current is collected by internal bus bars and brought through the transformer cover by the bus bars or by high-current bushings.

The power input to the furnace is controlled by adjusting the output voltage of the furnace transformer. Optimum performance of the furnace may require adjustment of the secondary voltage over a range of 3:1 or more. This may be accomplished by a regulating transformer between the high-voltage power source and a fixed-ratio furnace transformer. More frequently, regulation is obtained by taps in the high-voltage winding. In addition to taps in the high-voltage winding, a delta-Y switch in the high-voltage winding is often used to extend the range of voltage by an additional ratio of 1.73.

Motor-operated off-load tap changers are usual, but occasionally on-load tap-changing equipment is justified by the saving in melt time and reduced breaker maintenance. The load-tap-changing duty is more severe than on the usual power transformer, not only with respect to frequency of operation but also because of the extreme range, which results in large kVA increments per tap.

Circuit reactance furnishes current stability for ac arc furnaces. In the larger sizes, the inherent impedance of the transformer and its associated secondary conductors is sufficient for adequate stability. This is not generally true for smaller arc furnaces. Consequently, it is customary in furnace transformers rated 7500 kVA and below to include a reactor in the tank with the transformer. This reactor is connected in the high-voltage circuit and is furnished with taps to permit adjusting the total reactance to that required to maintain arc stability under the existing service conditions.

10.1.21 Grounding Transformers

A grounding transformer is intended primarily to provide a neutral point for grounding purposes. It may be a two-winding unit with a delta-connected secondary winding and a Y-connected primary winding which provides the neutral for grounding purposes, or it may be a single-winding 3-phase autotransformer with windings in interconnected Y or zigzag. With the latter, the windings consist of six equal parts, each designed for one-third the line-to-line voltage; two of these parts are placed on each leg and connected as in Fig. 10-45. In the case of a ground fault on any line, the ground current flows equally in the three legs of the autotransformer, and the interconnection offers the minimum impedance to the flow of the single-phase fault current.

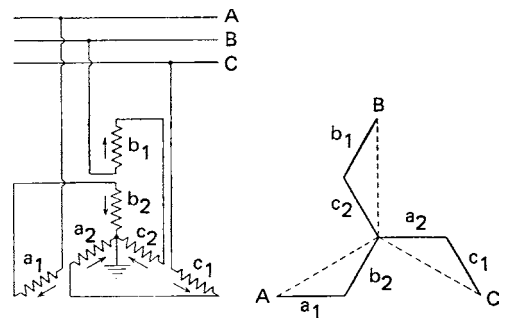


FIGURE 10-45 Grounding autotransformer with interconnected Y or zigzag windings.

10.1.22 Instrument Transformers

Functions. Instrument transformers are used to step transmission or distribution line voltages and currents down to levels that can be safely handled by metering and control devices. They are used to transform the primary voltage or current to values suitable for ratings of instruments, meters, relays, and other metering or control equipment. In a sense, they isolate the equipment from the lines. The normal secondary ratings are 5 A for current transformers and 115 or 120 V for voltage transformers. However, other current and voltage ratings are used depending on the application.

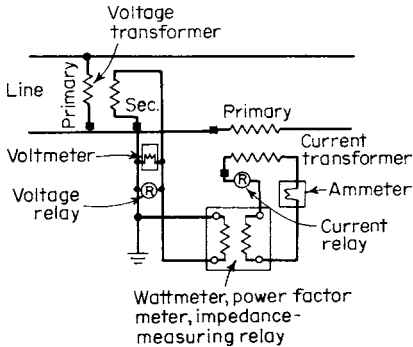


FIGURE 10-46 Voltage and current transformers as commonly connected to isolate meters, relays, and other equipment, and to transform current and voltage to convenient values.

To provide better protection, the secondary circuit should be grounded at one point. Metal cases should also be grounded.

The primary winding of a current transformer is connected in series with the load for which the current is to be measured or controlled. The primary winding of a voltage transformer is connected in parallel with the load for which the voltage is to be measured or controlled (Fig. 10-46). The secondary windings provide a current or voltage that is substantially proportional to the primary values for the operation of measuring instruments and control devices.

Polarity. When instrument transformers are used with measuring or control devices that respond only to the magnitude of the current or voltage, the direction of the current flow does not affect the response and the connections to the secondary terminals can be reversed without affecting the operation of the devices. When they are used with measuring or control devices that respond to the interaction of two or more currents, the correct operation of the devices depends on the relative phase positions of the currents, in addition to the magnitudes. To show the relative instantaneous directions of current flow, one primary and one secondary terminal are identified with a distinctive polarity marker, these indicate that at the instant when the primary current is flowing into the marked primary terminal the secondary current is flowing out of the marked secondary terminal (see Fig. 10-47).

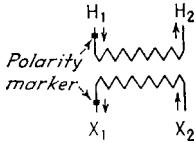


FIGURE 10-47 Polarity definition. Arrows indicate the instantaneous relative direction of currents in the windings.

Errors in Current Transformers. There are two types of errors that affect the accuracy of the measurements made with current transformers. The ratio-correction factor is the true ratio of the primary to the secondary current, divided by the nameplate ratio

$$F_{CR} = \frac{R_{CT}}{R_{CN}} \quad (10-66)$$

where F_{CR} = ratio correction factor of current transformer, R_{CT} = true ratio [(primary current)/(secondary current)], and R_{CN} = nameplate ratio [(primary current)/(secondary current)] of current transformer.

The phase-angle error is the angle of lead of the current leaving the marked secondary terminal over the current entering the marked primary terminal.

Relative Importance of Ratio and Phase Angle Errors. The ratio correction factor of current transformers affects the magnitude of the outputs. Therefore, they are important for meters that measure power for revenue purposes or other applications where the magnitude of the current is important. For example, a ratio correction factor of 1.010 indicates that the secondary current is lower than the correct value by 1% and that all measuring or control devices connected in the secondary circuit will have 1% less current than the primary current divided by the marked ratio.

The phase-angle error does not affect current-actuated devices such as ammeters or overcurrent relays, but the accuracy or operation of devices that respond to the products, the sums, or the differences of currents are affected by the phase-angle error. A wattmeter is a device that responds to the product of the voltage applied to the potential terminals, the current through the current coils, and the power factor which is the cosine of the angle between the voltage and current. The phase-angle error becomes very important if the power factor of the load being measured, such as measurement of the load losses in large power transformers, is small because the magnitude of the phase-angle error is significant compared to the angle between the voltage and the current in the devices being measured. If the current is supplied from the secondary of a current transformer with unity nameplate ratio, unity ratio correction factor, a phase-angle error of β , and primary current lagging the voltage, the wattmeter will not indicate the true watts, $EI \cos \theta$, but will indicate $EI \cos (\theta - \beta)$. If the sign of β is plus, the $\cos (\theta - \beta)$ will be larger than the $\cos \theta$ and the wattmeter will read high (see Fig. 10-48). If the sign of β is minus, the wattmeter will read low. To obtain the true watts, the apparent watts should be multiplied by the phase-angle correction factor K_β , which is dependent on both the phase-angle error of the transformer and the power factor of the load, as follows:

$$K_\beta = \frac{\cos \theta}{\cos(\theta - \beta)} = \frac{1}{\cos \beta + \sin \beta \tan \theta} \quad (10-67)$$

where K_β = phase-angle correction factor of current transformer, β = angle of lead of secondary current over primary current, and θ = angle of lag of load current behind load voltage.

Summarizing the Effect of Current-Transformer Errors. Ratio correction factors: Above 1.000 the secondary current is low, and below 1.000 the secondary current is high. Phase-angle errors with lagging load current: Positive phase-angle errors cause wattmeter readings to be high if the load-current power-factor angle is greater than the phase-angle error, and negative phase-angle errors cause the wattmeter readings to be low.

In practical metering problems β will be less than 30 min and K_β can be written

$$\begin{aligned} K_\beta &= 1 - \sin \beta \tan \theta = 1 - \tan \theta & \text{where } \beta \text{ is in radians} \\ K_\beta &= 1 - \beta \tan \theta / 3438 & \text{where } \beta \text{ is in minutes} \end{aligned} \quad (10-68)$$

The uncertainty in knowledge of the exact values of β and θ represents a greater error than will result from this simplification of Eq. (10-67).

Transformer Correction Factor. The transformer correction factor to be applied to the reading of the wattmeter for both the ratio and phase-angle errors is given by Eq. (10-69)

$$F_T = F_{CR} K_\beta \quad (10-69)$$

where F_T = transformer correction factor.

If F_{CR} and K_β are both between 0.985 and 1.015, Eq. (10-70) may be used with an error under ± 0.0003 :

$$F_T = F_{CR} + K_\beta - 1.000 \quad (10-70)$$

Classification of Errors. ANSI C57.13 classifies current transformers as to accuracy by a method which limits the total error in a wattmeter or watthour-meter reading resulting from the combination of ratio and phase-angle errors, over a range of power factors of the metered load of 0.6 to 1.0. The most accurate classification (usually specified for use with watthour meters for billing metering) is 0.3,

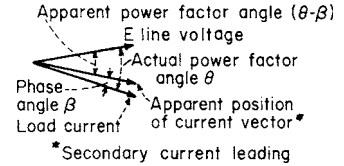


FIGURE 10-48 Effect of positive phase angle in increasing the apparent power factor.

which means that the total error at the meter caused by the current transformer will not exceed 0.3% at rated current (or at maximum continuous current), 0.6% at 10% rated current. ANSI C57.13 also recognizes 0.6 and 1.2 accuracy classes. The accuracy class is specified in connection with one or more of the standard burdens (see the next paragraph). For example, "0.3 B-0.2" describes a transformer of 0.3 accuracy class when loaded with a B-0.2 burden on the secondary terminals.

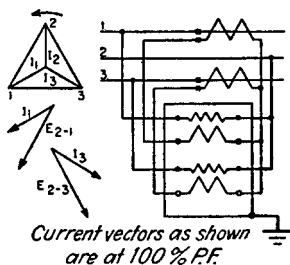


FIGURE 10-49 Metering connections for 3-phase, 3-wire lines with two watt-hour-meter elements.

Standard Burdens. ANSI C 57.13 also recognizes a number of standard values of secondary impedance loading (called "burden" in instrument-transformer parlance) for use in describing current transformer performance. The burdens are designated as B0.1, B0.2, B0.5, B0.9, B1.8 to mean impedances of 0.1, 0.2, etc., ohms at 0.9 power factor, and also B1.0, B2.0, B4.0, and B8.0 for corresponding impedances at 0.5 power factor. (These standard burden impedances are only applicable if rated secondary current is 5 A.)

Effect of Phase-Angle Errors on Metering 3-Phase 3-Wire Power with a Two-Stator Watt-hour Meter. With the meter connected as indicated in Fig. 10-49 with balanced load, if the marked ratio and ratio correction factor are both 1.000 and the phase-angle error β is the same for both current transformers

$$K_{\beta} = \frac{E_1 \cos(\theta + 30) + E_1 \cos(\theta - 30)}{[E_1 \cos(\theta + 30 - \beta) + E_1 \cos(\theta - 30 - \beta)]} = \frac{1}{\cos \beta + \sin \beta \tan \theta} \quad (10-71)$$

This is identical with Eq. (10-67) for a single-phase measurement.

Causes of Errors. The errors in a current transformer are due to the energy required to produce the core flux, which induces the secondary winding voltage that supplies the current through the secondary circuit. The total ampere-turns available to provide secondary current are vectorially equal to the primary ampere-turns minus the ampere-turns required to produce the core flux.

A change in secondary burden alters the flux required in the core and changes the core-exciting ampere-turns; leakage flux entering the core changes the magnetic characteristics of the core and affects the core-exciting ampere-turns.

Calculation of Ratio and Phase-Angle Errors. Calculation of ratio and phase angle in current transformers can, in theory, be done simply by first calculating the exciting ampere-turns required to magnetize the core and subtracting them from the primary ampere-turns to get the secondary ampere-turns (vectorial subtraction). The difficulty in calculation is that in many transformers the leakage flux which flows in only part of the core is as large as the working flux and its effect on exciting ampere-turns is most difficult to calculate (Wentz 1941). For exact determination of ratio and phase angle, therefore, actual measurement of ratio and phase angle as described in ANSI C57.13 is necessary.

Approximate calculation of ratio for relaying service is more practical and in fact often necessary because transformers supplying relays must often operate at currents up to 20 times normal or even higher, and exact measurements are extremely difficult and expensive. Accordingly, ANSI C57.13 recognizes an adequate ratio-error calculation method for current transformers in which the leakage flux which enters the core has only a negligible effect on performance. This calculation method is described in the Test Methods Section of C57.13. The ratio error calculated by this method may in fact be greater than the actual ratio error, but it is certain that it will not be less, a conservative result.

Generally, the leakage flux in a current transformer can be said to be negligible only in a current transformer consisting of a toroidal core with the secondary winding fairly well distributed around the core, for example, an assembly intended to be placed over a bushing in a circuit breaker or transformer and then only if the return conductor is at a distance at least as great as in typical circuit

breakers. If this type of transformer is used with a primary coil or even a single primary turn placed around one side of the core, it is doubtful that the leakage flux will be negligible.

Transformers with negligible leakage flux (principally bushing type) are designated in C57.13 as Class C transformers, meaning that it is safe to calculate the ratio error.

Classification of Current Transformers for Relaying Service. Transformers for which calculation of ratio will give conservative results are designated as Class C; all other transformers are designated as Class T, meaning that their performance must be determined by test. The performance of both types of transformers is then classified according to the voltage the secondary can deliver to the burden at 20 times rated secondary current without exceeding 10% ratio error. The established standard secondary terminal voltages are 10, 20, 50, 100, 200, 400, and 800, corresponding to the voltage required by ANSI standard burdens at 20 times normal current (100 A). A current transformer is classified by the letter C or T plus the standard voltage, such as C200 or T400.

Short-Time Current Limits. Current transformers may have to carry very large currents in the event of a short circuit of the system, especially when a low-rated branch circuit is supplied from a large system with a high fault-current capability. The large currents in the winding have two principal effects:

1. The primary winding is repelled from the secondary by the electromagnetic forces, which are proportional to the square of the current.
2. The windings heat very rapidly at a rate nearly proportional to the square of the current.

In order to apply current transformers properly, it is necessary to give them ratings:

1. Mechanical short-time rating, the current, usually stated in terms of times normal, which the transformer can withstand mechanically even if the current is initially fully offset.
2. Thermal short-time rating, the current which will not heat the winding to more than 250°C for copper conductors or 200°C for EC aluminum conductors. This limit is not to be demonstrated by test but is calculated on the conservative assumption that all the heat generated by the current is stored in the conductor.

C57.13 may be consulted for additional detail and for the test method to be used to demonstrate the mechanical limit.

Types of Construction. The types of current transformers are the wound type which consists of primary and secondary windings completely installed and permanently assembled on the magnetic circuit; the bar type, which is similar to the wound type except that the primary is a single straight and fixed turn; the window type, which has a secondary winding completely insulated and permanently assembled on the magnetic circuit and a window through which a conductor can be passed to provide a primary winding; and the bushing type, which is a special window type designed to fit over apparatus bushings, with the conductor through the bushing as the primary winding.

Current transformers are classified in accordance with the major insulation used as dry-type, compound-filled, molded, or liquid-immersed.

Safety Precautions. The secondary winding should always be short-circuited before disconnecting the burden. If the secondary circuit is open, with primary current flowing, all the primary ampere-turns are magnetizing ampere-turns and usually will produce an excessively high secondary voltage across the open circuit. All instrument-transformer secondary circuits should be connected to ground; when instrument-transformer secondaries are interconnected, only one point should be grounded. If the secondary circuit is not grounded, the secondary becomes, in effect, the middle plate of a capacitor, with the high-voltage winding and ground acting as the other two plates.

Errors in Voltage Transformers. There are two types of errors that affect the accuracy of the measurements made with voltage transformers. The ratio error is the difference between the true ratio of the primary to secondary voltage and the ratio that is marked on the nameplate. The phase-angle

error is the difference in the phase position of the voltage applied to the secondary burden and the voltage applied to the primary winding.

The ratio error is expressed as a ratio correction factor by which the secondary-voltage value should be multiplied to obtain a secondary voltage that is directly proportional to the primary voltage

$$F_{PR} = \frac{R_{PT}}{R_{PH}} \quad (10-72)$$

where F_{PR} = ratio correction factor of the voltage transformer, R_{PT} = true ratio (primary/secondary) of the voltage transformer, and R_{PN} = nameplate ratio (primary/secondary) of the voltage transformer.

The phase-angle error is designated by the symbol γ , is expressed in minutes, and is defined as positive when the voltage applied to the burden from the marked to the unmarked secondary terminal leads the voltage applied to the primary from the marked to the unmarked terminal.

Relative Importance of Ratio and Phase-Angle Errors. The effect of the ratio and phase-angle errors of voltage transformers is the same for current transformers, except that with a lagging power-factor load a positive voltage transformer phase-angle error will cause the wattmeter to read low. To obtain the true watts, the apparent watts should be multiplied by the phase-angle correction factor K_γ :

$$K_\gamma = \frac{\cos \theta}{\cos (\theta + \gamma)} = \frac{1}{\cos \gamma - \sin \gamma \tan \theta} \quad (10-73)$$

where K_γ = phase-angle correction factor of the voltage transformer, θ = angle of lag of load current behind load voltage, and γ = angle of lead of secondary voltage over primary voltage.

Classification of Errors. The errors in a voltage transformer change with the current required by the burden connected across the secondary terminals, the frequency, and the magnitude of the secondary voltage. ANSI C57.13 classifies voltage transformers as to accuracy by a method essentially the same as that for current transformers, the principal difference being that the limits of error apply over the range of rated voltage from 90% to 110% and from zero burden up to the burden at which the rating is given. The standard burdens for rating purposes are given in Table 10-8. The complete ANSI accuracy classification of a voltage transformer must include the secondary burden, such as 0.3X or 0.6Z.

Voltage transformers are made for all the standard rated circuit voltages. They are usually dry-type or molded for voltages below 23 kV and liquid-filled for the higher voltages.

Other Error Calculations and Corrections. The measurement of power by using a wattmeter and both current and voltage transformers requires a correction for the ratio and phase-angle errors of both of the instrument transformers and a correction for the phase angle α in minutes of the potential circuit of the wattmeter. Figure 10-50 shows the relative phase positions of the primary and secondary

TABLE 10-8 Standard Burdens for Voltage Transformers

From Table 13-11.110, ANSI C57.13

Burden designation	Secondary voltamperes*	Burden power factor
W	12.5	0.10
X	25	0.70
M	35	0.20
Y	75	0.85
Z	200	0.85
ZZ	400	0.85

*At 120 or 69.3 secondary volts, if rated secondary voltage is from 90% to 110% of 120 or 69.3 V.

voltages and currents of the instrument transformers if both β and γ are positive. If the potential circuit of the wattmeter is inductive by a small amount, the current in this circuit will lag the voltage and the phase angle will have the same effect as a negative voltage-transformer phase angle. The total phase-angle correction factor is

$$K_S = \frac{\cos(\theta + \beta - \gamma + \alpha)}{\cos \theta} \quad (10-74)$$

where K_S = total phase-angle correction factor, α = angle of lag of potential circuit of wattmeter, β = angle of lead of secondary current over primary current, γ = angle of lead of secondary voltage over primary voltage, and θ = angle of lag of secondary current behind secondary voltage.

The true watts, with all corrections included, is

$$P = WR_{CN}R_{PN}F_{CR}F_{PR}K_S \quad (10-75)$$

where F_{CR} = ratio-correction factor of current transformer, F_{PR} = ratio-correction factor of voltage transformer, P = watts drawn by load, R_{CN} = nameplate ratio of current transformer, R_{PN} = nameplate ratio of voltage transformer, and W = watts reading of wattmeter.

In watt-hour meters, the phase angle corresponding to α is corrected for in the meter by the lag adjustment or by making an overall calibration and adjustment for all errors, including the ratio and phase-angle errors of the instrument transformers.

Figures 10-51 and 10-52 show typical ratio-correction-factor and phase-angle curves for a current and a voltage transformer.

Consider the following example in which a load is measured with 50/5-A current transformer, with a 12.5-VA 90% power-factor burden characteristic curve according to Fig. 10-51 with 2300:115 V voltage transformer rated 200 VA with a 75-VA 85% power-factor burden characteristic curve according to Fig. 10-52 and with a lag angle of 6 min in the wattmeter potential circuit. What is the load true watts when the instruments read 500 W, 115 V, and 5 A, calibration errors of instruments being neglected? From Fig. 10-51

$$F_{CR} = 0.9997 \quad \beta = -2'$$

From Fig. 10-52

$$F_{PR} = 0.9984 \quad \gamma = +1'$$

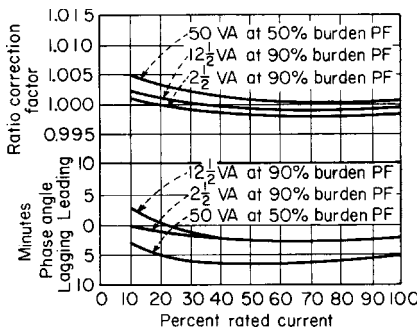


FIGURE 10-51 Typical curves of the ratio correction of phase angle for a current transformer.

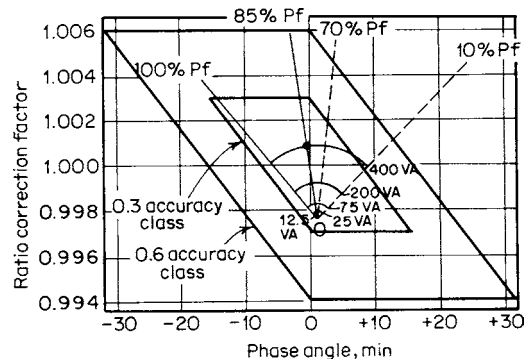


FIGURE 10-52 Typical curves of ratio-correction factors and of phase angle for a voltage transformer.

Stated above

$$\alpha = +6'$$

$$\theta = \cos^{-1} \frac{500}{5 \times 115} = \cos^{-1} 0.86957 = 29^\circ 35.47'$$

From Eq. (10-74)

$$K_s = \frac{\cos(29^\circ 35.47' - 2' - 1' + 6')}{\cos(29^\circ 35.47')} = \frac{0.86914}{0.86957} = 0.9995$$

From Eq. (10-75)

$$P = 500 \times 10 \times 20 \times 0.9997 \times 0.9984 \times 0.9995 = 99760$$

Ferroresonance in voltage transformers can occur when a voltage transformer is connected line to ground on an ungrounded system if the capacitive reactance, line to ground, can equal the exciting reactance of the voltage transformer, a condition which typically occurs at considerable over-voltage. A parallel resonant circuit of very high impedance is formed, raising the line-to-ground voltage considerably above normal; if the voltage is high enough, the voltage transformer will fail due to excessive exciting current or high-voltage stresses.

Measures taken to reduce the incidence of ferroresonance include operation at low flux densities, resistance loading of the secondaries, and insertion of resistance in the connection of the voltage transformer primary neutral to ground.

Transient performance of current transformers with initially offset primary current has been given a great deal of study in recent years. It has been realized for many years that a transformer has difficulty in transforming the dc component of an offset current. No one method of calculation has been generally acceptable but study of the references will help one to arrive at a solution of most practical problems.

10.2 CIRCUIT BREAKERS

By DAVID S. JOHNSON, JEFFREY H. NELSON and TED W. OLSEN

Definitions of terms used in this section can be found in the IEEE standards and application guides referenced in this section and/or in the *IEEE Authoritative Dictionary of Terms*.

10.2.1 Fundamentals

Definitions. *Circuit breakers* are mechanical switching devices capable of making and breaking currents under either normal or specified abnormal (short circuit) conditions on the power system. Though circuit breakers are primarily defined by their protective capabilities and ratings under abnormal short circuit conditions, they also perform switching duties under a myriad of other system conditions, each of which has its own set of switching stresses.

Circuit breakers are rated primarily by power frequency voltage, insulation levels (BIL, switching impulse, hi-pot voltage), continuous current, short-circuit current, and interrupting time. Reference is made to IEEE C37.100¹ for definitions of ratings subjects, and to IEEE C37.04² and IEEE C37.06³ for values of ratings typically applied to circuit breakers.

Circuit breakers employ a variety of media for high voltage insulation and/or current interruption. The type of media employed in a specific design is often designated as a prefix in the naming of the circuit breaker, for example, vacuum circuit breaker, or sulfur hexafluoride (SF₆) gas circuit breaker.

Circuit breakers are often categorized as being of either "dead tank" or "live tank" design. In the dead tank case, the interrupting contact system is enclosed in a grounded tank, typically surrounded by an insulating fluid (oil) or gas (SF₆) (see Figs. 10-53 and 10-54 for examples of dead tank circuit breakers).

The electrical current enters the tank through high voltage entrance bushings (Fig. 10-55), passes through the contact system, and then exits through another high voltage entrance bushing. In the live tank case, the interrupting contact system is supported by insulators at some height above ground potential, but is not contained within a grounded tank system (see Figs. 10-56 and 10-57 for examples of live tank circuit breakers). There is no grounded tank or enclosure surrounding the live parts. Dead tank design allows the placement of current transformers, which are necessary for protective relaying input signals, around the high voltage entrance bushing. Live tank design offers no location to place current transformers, and therefore must be independently placed adjacent to the circuit breaker.

History of Development. In the early days of electrification (1890), switches were of the hand-operated, knife-blade type.

Air Switches. With increasing current and voltages, spring-action driving mechanisms were developed to reduce contact burning by faster-opening operation. Later, main contacts were fitted with arcing contacts of special material and shape, which opened after and closed before the main contacts. Further improvements of the air

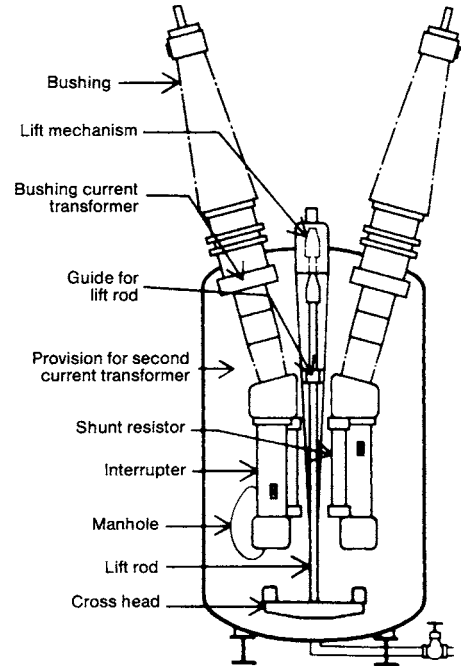


FIGURE 10-53 Outline of a dead-tank 161-kV outdoor oil circuit breaker.

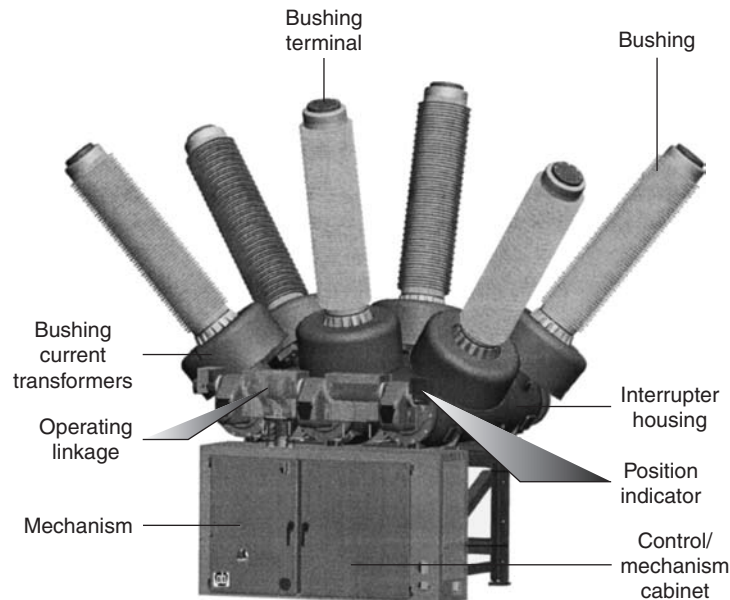


FIGURE 10-54 Dead-tank SF₆ circuit breaker rated 245 kV, 63 kA.

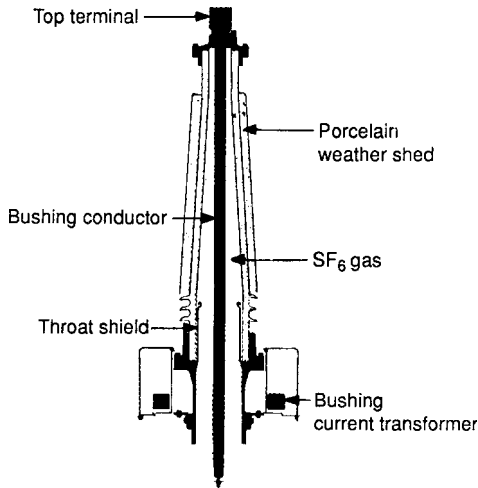


FIGURE 10-55 Gas-filled bushing.

Europe, and make the special low-oil-volume interrupting chambers of extra-light weight. By means of current-dependent oil streams in different directions and supported by oil injection, the arc is cooled and extinguished effectively. The interrupters are mounted on porcelain or molded-resin supports, thus avoiding oil as an insulating medium to ground.

Standard transformer oil can be used for both oil and minimum-oil circuit breakers.

Air-Blast Circuit Breaker. Further increase of system voltages and generating capacities triggered the search for faster and stronger circuit breakers utilizing oilless arc interruption. After 1940, the air-blast circuit breaker was developed, making use of the good insulating and arc-quenching properties of dry and cleaned compressed air.

switch were the brush-type contact with a wiping and cleaning function, the insulating barriers leading to arc chutes, and blowout coils with excellent arc-extinguishing properties. These features, as well as the horn gap contact, are still in use in low-voltage ac and dc breakers.

Oil Circuit Breaker. Around 1900, in order to cope with the new requirement for “interrupting capacity,” ac switches were immersed in a tank of oil. Oil is very effective in quenching the arc and establishing the dielectric strength of an open break after current zero. Deion grids, oil-blast features, pressure-tight joints and vents, new operating mechanisms, and multiple interrupters were introduced over several decades to make the oil circuit breaker a reliable apparatus for system voltages up to 362 kV.

Minimum-Oil Circuit Breaker. These breakers were developed after 1930, used mainly in

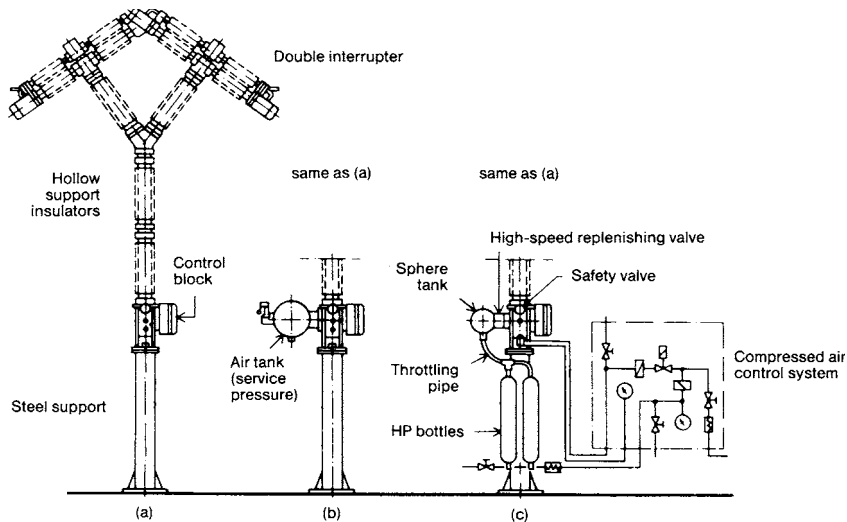


FIGURE 10-56 Modular setup of a 362-kV outdoor air-blast circuit breaker with two uprating steps: (a) without air tank, low braking capability; (b) with air tank, standard breaking capability; (c) with constant-pressure air supply and high breaking capability.

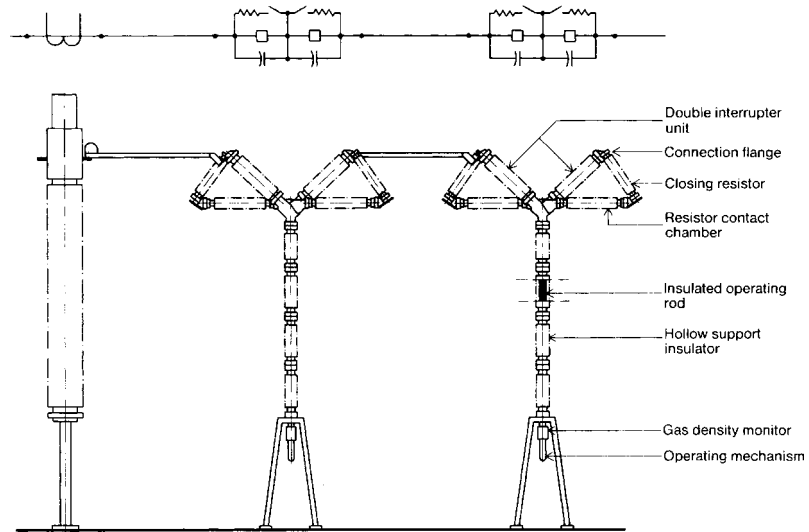


FIGURE 10-57 Live-tank SF_6 outdoor circuit breaker and current transformer arrangement, 800 kV, 3000 A, 40 kA.

Figure 10-58 shows a typical air-blast circuit breaker of modular design, installed in 1950.

Further development of the air-blast circuit breaker led to two-cycle interrupting time, extra-heavy interrupters, and the constant-pressure control system.

The *magnetic air circuit breaker* uses a combination of a strong magnetic field (coil or soft iron plates) with a special arc chute to lengthen and cool the arc until the system voltage cannot maintain the arc any longer. This interrupting principle was applied mainly in the distribution voltage range in metal-clad switchgear from the 1940s to the 1980s.

SF_6 Gas Circuit Breakers. SF_6 gas circuit breakers were first developed in the early 1950s by Westinghouse Corporation, following the discovery of the excellent arc quenching and insulating properties of SF_6 gas (see Fig. 10-59). Both live tank and dead tank designs were introduced from the late 1950s into the 1960s. SF_6 remains the dominant insulating and arc-quenching medium at higher voltages (72.5 kV and above) even today.

Dead tank SF_6 gas circuit breakers were incorporated into gas-insulated substations (GIS) up to 800 kV from the mid-1960s through the present. Gas insulated substations offer space savings and

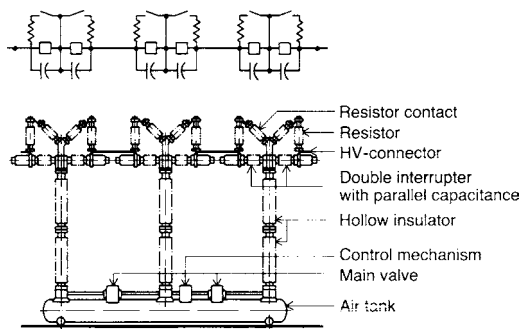


FIGURE 10-58 Outdoor air-blast circuit breaker 230 kV, 10009 A, 16 kA, 3-cycle interrupting time.

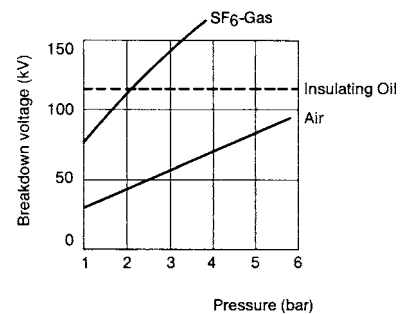


FIGURE 10-59 Breakdown voltage of oil, air, and SF_6 gas as a function of pressure at 38 mm ($1\frac{1}{2}$ in) electrode distance.

environmental advantages over conventional outdoor substations, using the reduced insulation gap requirements of SF₆ gas.

SF₆ gas circuit breakers were initially of the two-pressure type, in which high pressure gas for interruption is compressed and stored for later interrupting duty. Later designs employed the puffer principle, in which interrupting pressure is developed during the contact motion itself, and no high pressure gas is stored. The latest designs of SF₆ gas circuit breakers utilize the arc thermal energy itself to develop the interrupting pressure; these designs are referred to as *self-blast* or *thermal-assist* circuit breakers.

Vacuum Circuit Breakers. Vacuum interrupter technology is a relatively recent development, from the 1960s to 1970s. Vacuum circuit breakers employ a vacuum bottle, which includes the contact system. The contacts within the vacuum bottle are driven, through a bellows, by a low energy mechanism. The contact stroke of vacuum circuit breakers is short, which leads to very reliable, low mechanical-energy designs. Vacuum interrupters have now improved in their range of voltages, short-circuit currents, and continuous current capabilities, such that most medium voltage application requirements can be met. Vacuum circuit breaker designs have become the dominant technology for outdoor breakers and metal-clad switchgear applications at 38 kV and below.

Design Fundamentals. Circuit breaker designs typically consist of the following construction elements: (1) contact system or interrupter, at high voltage; (2) insulation between the contact system and ground potential (SF₆ gas, porcelain, molded resin); (3) operating mechanism and related control systems; and (4) an insulated link between the operating mechanism and the high voltage contact system. In addition, dead tank circuit breakers incorporate high voltage entrance bushings that carry current at high voltage through the circuit breaker tank shell. Dead tank designs may also include bushing type current transformers (BTCT), which are conveniently placed around the conductor of the high voltage entrance bushings.

Tripping facilities. Tripping facilities, including circuit breaker controls, and the mechanical tripping mechanism of the circuit breaker operating mechanism, are vital to ensure proper operation during all conditions.

Short Circuit Duty. The *short-circuit duty* is determined by the maximum short-circuit that the rotating machinery connected to the system at the time of short circuit can pass through the breaker to a point just beyond the breaker, at the instant the breaker contacts open. The short-circuit current is determined by the characteristics of synchronous and induction machines connected to the system at the time of the short circuit, the impedance between them and the point of short circuit, and the elapsed time between the starting of the short circuit and the parting of the breaker contacts.

In *calculating* short-circuit currents of high-voltage ac circuit, it is ordinarily sufficiently accurate to take into account only the reactance of the machines and circuits, whereas in low-voltage circuit resistance as well as reactance may enter into the calculation. In dc circuit, resistance only is ordinarily sufficient.

For first *approximations*, the reactance and typical time-decrement curves of the synchronous machines may be used. For close calculations, the actual reactances and time characteristics of the equipment should be used, and calculation made for single- as well as 3-phase faults. The “per unit” impedance system and the “internal voltage” method, using “symmetrical components,” are often used in more exact calculations. Programs are available for digital computer studies of system short-circuit currents, both balanced 3-phase and phase-to-ground.

The *interrupting capacity*, in kilovolt amperes, is the product of the phase-to-ground voltage, in kilovolts, of the circuit and the interrupting ability, in amperes, at stated intervals and for a specific number of operations. The current taken is the rms value existing during the first half-cycle of arc between contacts during the opening stroke.

Symmetrical Current Basis. It has become a widely adopted practice to determine the interrupting capability of circuit breakers in kiloamperes symmetrical. The rated short-circuit current in rms kiloamperes is referred to the rated maximum voltage in kilovolts.

The ratings structure and tables of ratings for ac high-voltage circuit breakers are found in IEEE C37.04² and IEEE C37.06³.

The short-circuit current interrupting process is characterized first by an arc appearing between the breaker contacts. The arc contains a high conductivity plasma column originating from the high temperature and related gas ionization (in the case of gas-blast interrupters). Interruption will occur at current zero and in this case is first determined by successful cooling of the arc (through gas flow) to eliminate the ionized gas conductive path, and then the race to build up dielectric strength of the open contact gap faster than the rise of the power system recovery voltage.

Several specific problems are encountered during the interrupting process of gas-blast interrupters:

1. Arc plasma temperatures exceeding 20,000 K.
2. The turbulent supersonic flow of the quenching gas in a changing flow geometry with speeds ranging from a few hundred meters per second to several thousand meters per second.
3. The interrupter-moving system and its drive accelerates the moving masses in the few thousandths of a second to speeds as high as 10 m/s while simultaneously compressing the quenching gas.
4. The stress places on the network system by the current interruption and the recovery voltage.

The *interrupting principle* of an SF₆ puffer-type interrupter is sketched in Fig. 10-60. On opening, the fixed and moving contacts are pulled apart by the operating mechanism. Thus, the fault current is forced to flow along the arc plasma. The contact movement combined with the compression cylinder movement in the opposite direction compresses the quenching gas inside the cylinder. The quenching gas is consequently forced to flow through the contact system, and the insulated nozzle toward the exhaust. This intensive flow of quenching medium along the arc rapidly removes the energy converted within the arc plasma and transforms the path between the open contacts into an insulating gap.

DC Interruption. DC interruption (see Fig. 10-61) is basically different from ac interruption. After contact parting, the arc is lengthened and cooled and consequently the arc voltage is rising. The current will extinguish after the change in current di/dt becomes negative and the arc voltage rises above service voltage. DC circuit breakers must therefore operate fast, in order to allow the voltage to build up in a few milliseconds. The energy originating from the generator and inductance will have to be absorbed by the arc. Magnitude and duration of short-circuit current depend on the height of network inductance. With rising inductance, the short-circuit current will decrease, whereas the duration of the arc will increase.

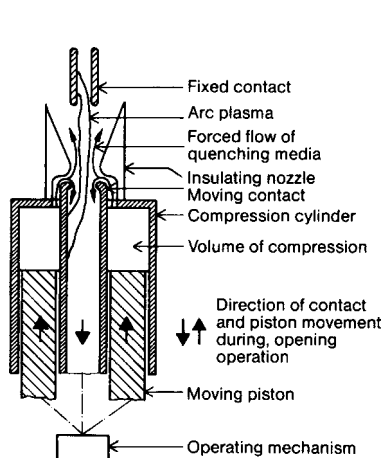


FIGURE 10-60 Principle of puffer-type arc interrupter.

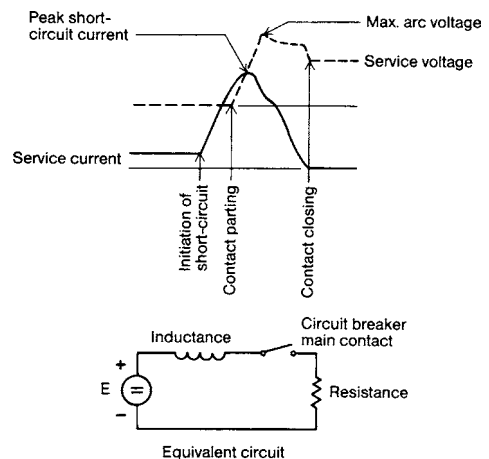


FIGURE 10-61 Direct-current interruption; typical shape of short-circuit current and recovery voltage.

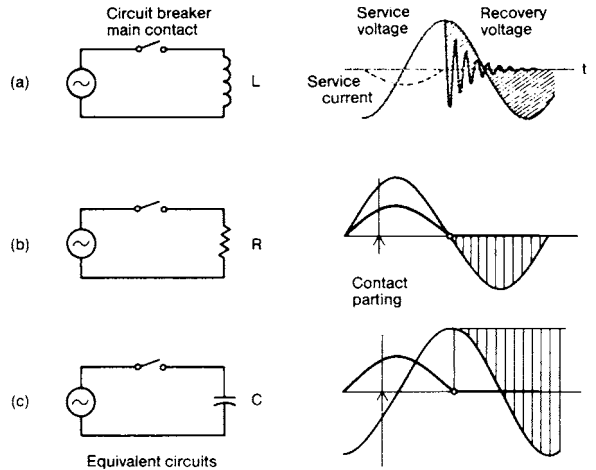


FIGURE 10-62 Typical shape of recovery voltage on interruption: (a) induction current; (b) resistive current; (c) capacitive current.

AC Interruption. AC interruption occurs at current zero. During the following half-cycle, the *recovery voltage* will build up across the circuit breaker main contacts. The typical appearance of recovery voltage will differ in inductive, resistive, and capacitive circuits (see Fig. 10-62). When opening an inductive circuit, the recovery voltage will rise suddenly at a high rate because current interruption occurs at the moment of system voltage peak. This case requires fast building of dielectric strength of the open contact gap.

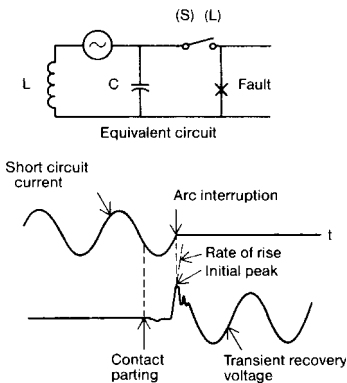


FIGURE 10-63 Alternating-current interruption; typical shape of short-circuit current and transient recovery voltage.

When interrupting resistive load, current and voltage pass through zero at about the same moment. The recovery voltage will therefore rise at a moderate rate and no particular problems are imposed on the circuit breaker.

At the moment of interruption of capacitive current, the capacitance is fully charged. The recovery voltage rises slowly during the first half cycle but continues to rise to a value twice the system voltage. This may lead to restrikes, undesired network oscillations, and overvoltages.

The waveforms of short-circuit current and transient recovery voltage in a simplified network system are shown in Fig. 10-63. At the moment of fault-current interruption the two sections—source side (S) and line side (L)—of the network are decoupled and oscillate independently about their driving voltage. The difference of these two transients appears across the open contacts of the breaker pole. The behavior of this transient recovery voltage is determined by the circuit parameters. The still-moving or already fully-open breaker contacts must be able to withstand the recovery voltage. The most severe stress for the open contact gap is the *initial peak* and the *rate of rise* (kV/ μ s) of the recovery voltage.

If the recovery voltage exceeds the gap insulation, the arc will restrike and current will continue until the next current zero, when interruption will again be attempted. The rate of rise of recovery voltage is a function of the constants of the circuits which supply power through the breaker. The larger the adjacent capacitance to ground before the major inductance limiting the fault current, the slower will be the rise of the recovery voltage. Some breakers modify the recovery voltage characteristics by limiting the current, modifying its power factor, and so on.

10.2.2 Severe Interrupting Conditions

The following severe cases of circuit-breaker switching conditions have to be considered carefully: terminal fault, short-line fault, out-of-phase switching, switching of small inductive currents, switching of capacitive currents, closing on a fault. The chosen examples are typical only; they are uniformly based on similar and simplified network configurations and are restricted to single-phase fault conditions. Other switching conditions may also be important.

Terminal Fault. After interruption of short-circuit current, the recovery voltage oscillates toward the service frequency driving voltage via an initial peak. The natural frequency is determined by the inductance and capacitance of the driving system (Fig. 10-64).

The dc component of the short-circuit current depends on the time constants of the network components like generators, transformers, cables, and high-voltage lines and their reactances of the zero-sequence and the positive sequence networks. The recovery voltage will accordingly vary depending on the location of the circuit breaker within the network.

Short-Line Fault. In the case of a short-line fault, a section of line lies between the breaker and the fault location (Fig. 10-65). After the short-circuit current has been interrupted, the oscillation at the line side (L) of the breaker assumes a superimposed “saw-tooth” shape. The rate of rise of this line oscillation is directly proportional to the effective surge impedance and the time rate of change of current (dI/dt) at current zero. The component on the supply side (S) basically exhibits the same waveform as a terminal fault. The circuit breaker is stressed by the difference between these two voltages. Because of the high frequency of the line oscillation, the transient recovery voltage has a very steep initial rate of rise. Since the initial rate of rise increases with increasing rate of current change, the limiting interrupting capability of many breaker designs is determined by the short-line fault.

Out-of-Phase Switching. Two network systems with driving voltages E_1 and E_2 are connected via a high-voltage transmission line (Fig. 10-66). Since the circuit is closed via the closed circuit breaker, the resulting driving voltage is equal to the sum of the two system voltages. Driving voltage E_2 may, for example, exceed voltage E_1 by the voltage drop across the transmission line. After opening the breaker, the transient recovery voltages of the disconnected networks oscillate independently.

The circuit breaker is stressed by the difference of these two voltages. In the case of disconnection of long lines, the recovery voltage across the breaker could be increased because of the Ferranti effect, where the voltage of the receiving end can be up to 15% higher than the sending end if the line is lightly loaded.

Interruption of Small Inductive Currents. This occurs (see Fig. 10-67) when disconnecting unloaded transformers, reactors, or compensating coils. An arc is produced between the contacts when the circuit breaker is opened. The arc voltage is approximately constant at higher currents, since the arc energy is removed only by convection. With small currents, the arc voltage increases as a result of arc looping and a change in the cooling mechanism.

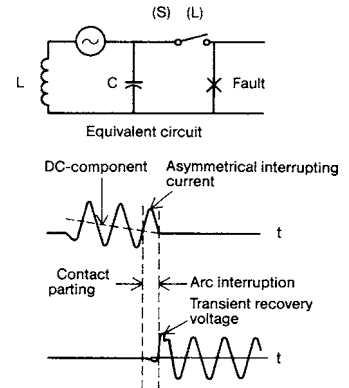


FIGURE 10-64 Principle of terminal-fault interruption, equivalent circuit; typical shape of short-circuit current and transient recovery voltage.

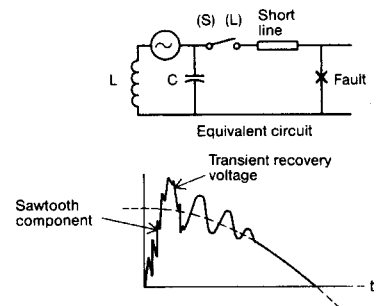


FIGURE 10-65 Principle of short-line fault interruption, equivalent circuit; typical shape of recovery voltage.

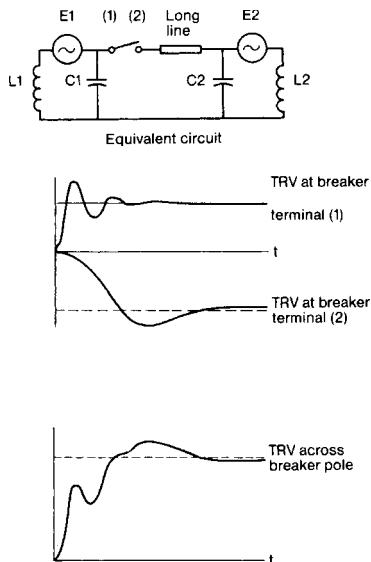


FIGURE 10-66 Principle of out-of-phase switching, equivalent circuit; typical shape of recovery voltage.

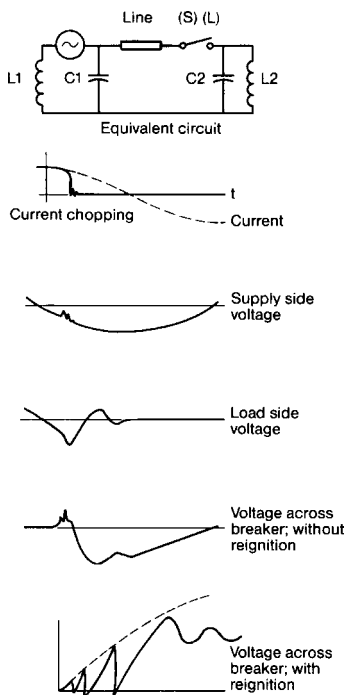


FIGURE 10-67 Principle of small-inductive-current interruption; equivalent circuit; typical shape of current and voltage.

When approaching current zero, the arc current begins to oscillate as a result of interaction with the system; that is it becomes unstable.

As a result of the high oscillation frequency, the current interruption may occur prior to the natural zero passage, can be regarded as instantaneous, and is called *current chopping*. The chopping current is affected not only by the properties of the circuit breaker but also to a great extent by the system parameters.

Energy at the disconnected load side (L) oscillates with the natural frequency of the capacitances local to the circuit breaker. The maximum voltage is attained at the moment when all the energy is converted into capacitive energy.

As a result of the resistive losses, the voltage on the disconnected load side decays to zero. During current chopping, the breaker is stressed by the supply-side voltage on one side and by the load voltage on the other side. The supply side voltage is at a maximum, since the load is highly inductive. The load side voltage is the oscillating voltage as the energy exchanges from inductive energy to capacitive energy. This load side voltage will have a high frequency of up to several thousand cycles per second. During this increasing stress, reignition across the breaker may occur.

However, the arc is immediately extinguished again because of the low current and the process begins anew. Hence, the reignition also helps reduce the energy stored in the disconnected circuit.

Interruption of Capacitive Currents. Capacitive currents occur during line drooping as well as during disconnecting unloaded cables or capacitor banks (Fig. 10-68). Although, switching of capacitor banks is regarded as a special application, disconnecting of charged lines is a frequent switching operation.

Current chopping may occur at a low instantaneous current value during interruption of capacitive currents, but this does not lead to overvoltages. After interruption of current, the voltage at the line capacitance (L) remains at the peak value of the power frequency voltage, whereas the voltage on the source side (S) oscillates about the driving voltage. The difference between the two voltages appears across the circuit breaker with an amplitude of more than double the rated voltage. If the circuit breaker cannot withstand this higher voltage *restriking* may occur. Restriking is similar to closing transmission lines with trapped charge. After restriking, a transient current flows through the circuit breaker, which is of higher frequency than that of the system and which can again be interrupted during the reignition process. After *reextinction*, the line is charged to the potential of the peak value of the equalizing process, whereas the circuit-breaker terminal on the source side (S) recovers to the system voltage. A very high differential voltage appears across the breaker, which may lead to renewed restriking and even switching failures. Restrike-free

interruption of capacitive currents is thus of the utmost importance. Basically, the same phenomenon occurs during disconnection of capacitor banks. To determine the voltage stresses of the circuit breaker, however, the grounding condition of the supply system and capacitor bank and the arrangement of the bank have to be taken into account.

Closing on a Fault. This (see Fig. 10-69) directs the stress onto the circuit breaker contact system, particularly as regards the electrodynamic and thermal forces. The current and voltage stress is different during closing on (a) symmetrical or (b) asymmetric short-circuit current.

The deciding factor is the moment of contact touch relative to the phase angle of system voltage. In case contact touch and consequently ignition of the arc occurs at the voltage maximum, the short-circuit current will appear symmetrical. The other extreme case takes place with the moment of closing at voltage zero. Here the asymmetrical short-circuit current contains the maximum dc component. A contact system designed for fast closing operation will be subjected to a shorter arcing time and consequently to reduced contact burning when closing on symmetrical currents. Fast operation is therefore not only important for opening but also for circuit-breaker closing.

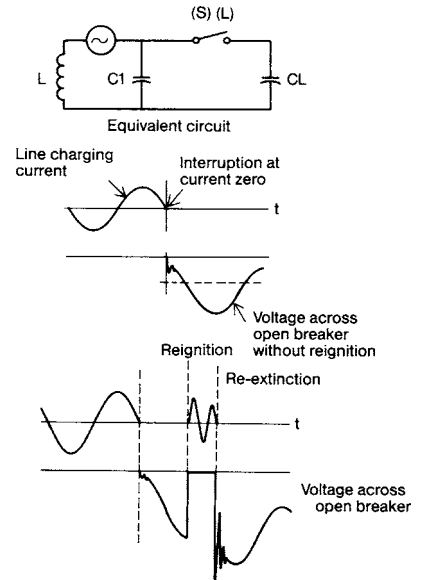


FIGURE 10-68 Principle of capacitive current interruption, equivalent circuit; typical shape of current and voltage.

10.2.3 Ratings and Selection

Voltage Rating and Insulation. Circuit breakers are built for voltage ratings as defined in IEEE C37.04² and IEEE C37.06³. They have to be dimensioned to withstand the maximum voltages as specified. The rated maximum voltage is the upper limit for operation.

For circuit breakers rated in accordance with ANSI C37.06-1987⁴ (or earlier), the range between upper and lower limit is defined by voltage range factor K . Current-interrupting capabilities vary within this range in inverse proportion to the operating voltage.

For circuit breakers rated in accordance with ANSI C37.06-1997⁴ (or later), the current-interrupting capability is a constant kA value at any voltage equal to or lower than the rated maximum voltage.

The insulation level is determined by the rated withstand test voltages specifying the low-frequency voltage (kV, rms) and the impulse voltage (kV, crest). High-voltage breakers must essentially withstand switching surges and both full and chopped-wave lightning impulses. For multiple-break circuit breakers, equal voltage distribution over the series breaks is achieved by grading capacitors paralleled to the interrupting chambers. Coordination between inner and outside insulation, as well as insulation coordination between interrupters and ground insulation, has to be properly designed to prevent flashover inside the breaker or over the open break.

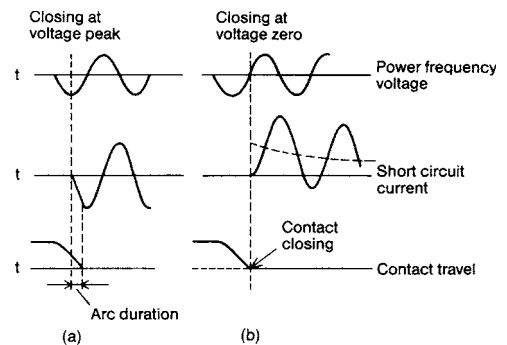


FIGURE 10-69 Stress on contact when closing on a fault, contact travel related to (a) symmetric, and (b) asymmetrical short-circuit currents.

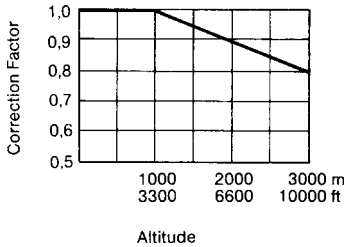


FIGURE 10-70 Altitude-correction factor for voltage ratings.

Outdoor breakers are generally available with special bushings that provide increased creepage distance for installation sites with highly contaminated air. For heavily polluted atmospheres, spray washing of live or deenergized breakers may be an additional measure. Because of the method of design with enclosed ground insulation, the GIS circuit breaker is not influenced by atmospheric pollution.

For installation at altitudes above 3300 ft (1000 m), altitude correction factors have to be applied (Fig. 10-70). The values of rated maximum voltages and insulation levels are multiplied by these factors to obtain the values for the application. The altitude correction factors are as listed in ANSI/IEEE C37.04-1979. Correction factors are under discussion in an IEEE Switchgear committee working group and are expected to change. These factors will be published in IEEE C37.100.1⁵.

Particular reference is made to the rating structures and preferred ratings for ac high-voltage circuit breakers per the latest standard revisions of IEEE C37.04² and IEEE C37.06³.

Continuous Current Rating. The *rated continuous current* is the current a circuit breaker has to be able to carry continuously without exceeding a specified temperature rise limit in a specified ambient temperature. Attention must be paid to reduction factors arising from the kind and site of installation, class of insulation material, and electrical endurance requirements.

High-voltage ac breakers must be able to interrupt the rated short-circuit current (kA, symmetrical). They shall be capable of performing the required closing-latching-carrying-interrupting duties in immediate succession. The closing and latching capability (peak kA) is 2.6 times rated short-circuit current (kA, symmetrical) for circuit breakers rated in accordance with ANSI C37.06-1997 (or later). For circuit breakers rated in accordance with ANSI C37.06-1987 (or earlier), the closing and latching capability (rms asymmetrical kA) is 1.6 K times rated short-circuit (kA, symmetrical). The current-carrying capability is determined by the 3-s short time current (kA, rms).

Selection and Application. The proper selection and application of circuit breakers is an extremely important element in the design of an electrical system. Breakers are relied on to separate a defective portion of the system from the remainder to prevent the spread of damage and to permit the good portion to continue in service.

Application conditions and considerations for ac high-voltage circuit breakers are outlined in the latest revision of IEEE C37.010⁶, C37.011⁷, C37.012⁸, and C37.015⁹.

Among others, the following criteria have to be considered when selecting a circuit breaker:

System data, such as maximum system voltage, insulation level, short-circuit requirements, and line or cable parameters.

Switching conditions, such as service currents; switching of unloaded transformers, unloaded lines and cables, choke coils, capacitors, generators, and motors; interrupting short-circuit currents and performing special duties like phase opposition, evolving fault, closing on a fault, closing on long lines; duty cycle, reclosing, and operating times.

Service requirements, such as special application for industrial plants, hazardous plants, furnace duty, railway duty, marine duty, maintenance, and operation.

Site of Installation, altitude above 3300 ft, climactic conditions, humidity, wind load, ice, air contamination, space requirements, environmental requirements, earthquake, connection to and function with other switchyard and network components, open installation, or metal-clad switchgear.

10.2.4 Operating Functions

Opening Operation and Duty Cycle. Reaction time and speed of modern breakers has increased to reach standard interrupting times of 2 to 5 cycles, with 2 to 3 cycles being common at high

voltage. Interrupting time is measured from energizing of the trip coil until the extinguishing of the arc. The interrupting time during close-open operations may exceed the rated interrupting time by either $\frac{1}{2}$ cycle (for 2 and 3 cycle breakers) or by 1 cycle (for 5 cycle breakers).

The current standard operating duty cycle consists of the following:

Open—T—Close—Open—3 min—Close—Open

T is defined as either 15 s or 0.3 s depending on whether the circuit breaker is rated for high speed reclosing; this distinction is important in application. Even circuit breakers rated for high speed reclosing must still be allowed a 0.3-s delay to allow for proper recovery of insulation following the initial fault interruption.

For existing oil and air-magnetic circuit breakers, the standard operating duty cycle was: Open—15s—Close—Open. For additional operations, and/or any close operation in the duty cycle with a time delay of less than 15 s after an opening operation, the interrupting rating and related required capabilities of the oil or air-magnetic breaker have to be derated. All operations within a 15-min period are considered part of the same duty cycle and a duty cycle shall have no more than five opening operations. For guidance on interrupting capability for reclosing service for oil and air-magnetic breakers manufactured after 1960 refer to IEEE C37.010⁶. Circuit breakers manufactured prior to IEEE C37.7-1960¹⁰ have different basis of rating.

Closing Operation. Circuit breakers are designed to perform the closing and reclosing operations as per standard requirements.

When operated to close on long lines, extra-high-voltage circuit breakers require special measures to keep switching overvoltages within specified limits. Such measures may be single or multiple step *closing resistors*, synchronously closing at the moment of voltage zero, or *polarity-controlled-closing*, which means closing during the period of equal polarity at the line and source side of the breaker.

When operated to close on capacitor banks special measures may be taken to limit transient currents and voltages. Such measures may be closing resistors; controlled closing at the moment of voltage zero for grounded wye capacitor banks; or controlled closing on ungrounded wye capacitor banks where the first phase is closed at the moment of voltage zero and the other two phases are closed at a point where the voltage difference between the two phases is zero.

When operated to close on power transformers or shunt reactors special measures may be taken to limit inrush transient currents and transient voltages. Such measures may be single or multiple step closing resistors, or controlled closing at the moment of voltage peak.

The magnitude of overvoltages on energizing and reenergizing is influenced by the nature and variables of the power system. Parameters of supply side and line must be taken into account in order to compute the overvoltages or to determine them using transient network analyzers or transient analysis software, such as electromagnetic transients programs (EMTP), power systems computer aided designs (PSCAD), or alternative transient program. (ATP).

For a summary of the magnitude of overvoltages occurring when energizing high-voltage lines, based on numerous studies and measurements in high-voltage networks, see Table 10-9. Surge arresters may also be used to limit switching overvoltages.

TABLE 10-9 Overvoltages Occurring When Energizing High-Voltage Lines

Prevailing condition	Overvoltage factor (per unit)
1. Line with trapped charge, no compensation, no means of reduction employed	>3
2. Line without trapped charge, no compensation, no closing resistors, or with trapped charge, no closing resistor, but polarity-dependent closing	2.0–2.8
3. Same as no. 2, but with compensation	2.0–2.5
4. Single-stage closing resistors, compensated line	≤2.0
5. Two-stage closing resistors, optimum compensation	≤1.7
6. Two-stage closing resistors, combined with polarity-dependent closing, or compensation with optimized multistage closing resistors	1.5

Operating Mechanism. Opening and closing of power circuit breakers under service conditions is seldom performed manually, since most breakers are installed in systems designed for remote control providing specific redundancy. Various means of operation are used, such as (1) dc solenoids, (2) solenoids operated from an ac source through a dry-type rectifier, (3) compressed air, (4) high pressure oil, (5) charged spring, and (6) electric motor. *Automatic reclosing* of breakers in overhead line feeders is frequently used to restore service quickly after a line trips out because of lighting or other transitory fault. Instantaneous or time-delay reclosing may be provided with a lockout to prevent more than one to several successive reclosures, as desired. If the fault is cleared before the lockout feature operates, the reclosing device resets itself, permitting a complete cycle of reclosing at a subsequent fault.

The circuit-breaker-operating device has to cope with the increasing requirements in interrupting and current-carrying capability as well as with shorter operating times. Simplicity of design, robustness, and reliability have to ensure safe operation of this vital link between the electrical system controls and the interrupter. The principle of a pneumatic drive is sketched for an extra-high-voltage circuit breaker which functions according to the differential piston principle in Fig. 10-71. A pneumatic interlocking device in connection with the SF_6 gas system ensures that the breaker always remains in the defined open or closed position even on loss of air pressure. Besides opening and closing functions, effective damping of the highly accelerated moving parts is incorporated.

Accessories. Circuit breakers may be equipped with a wide range of accessories, either required, like pressure controls, gas-density monitors, safety valves, and position indicator, or optional, such as a choice of different release, alarms, or auxiliary contacts. To illustrate the importance of accessories for safe and reliable circuit breaker operation, Fig. 10-72 shows the SF_6 gas monitoring system of a high-voltage SF_6 outdoor breaker.

The insulation and breaking capacity of an SF_6 breaker depends on the gas density. It is assumed that the volume remains constant during temperature variations, whereas the pressure of the SF_6 is highly dependant on temperature change. Hence, to monitor the state of the gas, it is logical to supervise not the pressure but the density of the gas.

The density monitor operates according to the principle of a temperature-compensated pressure gage, the characteristics of which correspond to the constant-density line. The SF_6 gas pressure acts on a metal bellows, the movement of which is transmitted by a transfer mechanism with a bimetal disk to the microswitch.

The density monitor is set for the operating pressure. The pressure-temperature diagram shows the standard case for this type of breaker, a minimum pressure of 5 bar, measured at 20°C . The density monitor emits a signal at 5.2 bar, indicating that refilling is necessary. If the pressure drops below 5 bar, operation of the breaker is blocked.

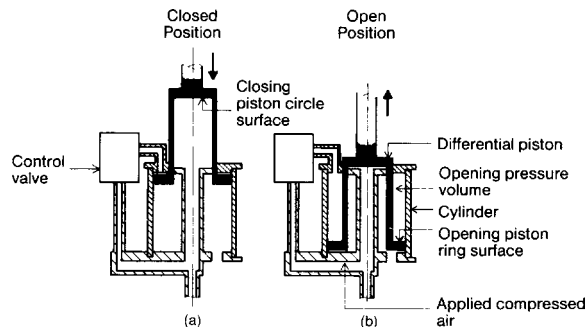


FIGURE 10-71 Principle of the drive system for an SF_6 outdoor breaker: (a) closed position; (b) open position.

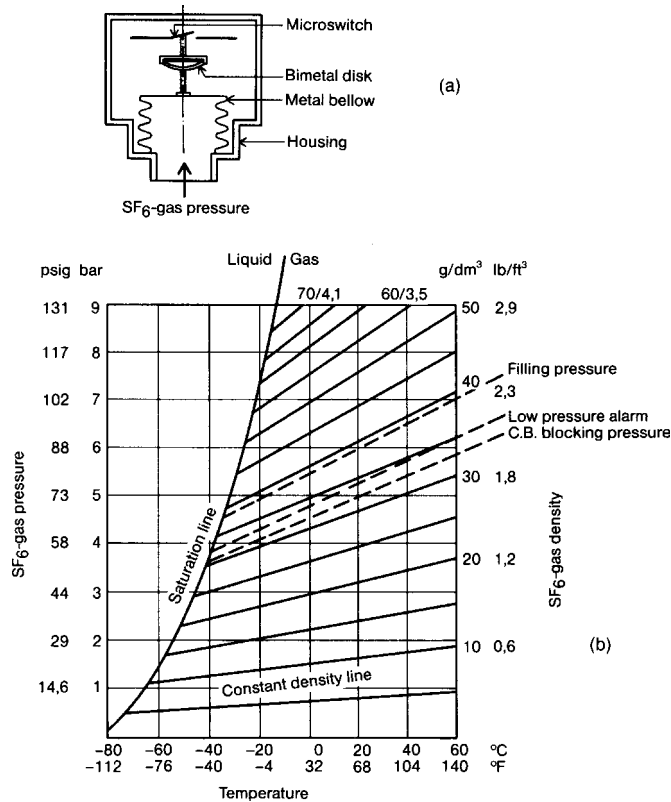


FIGURE 10-72 (a) Arrangement and (b) pressure-temperature diagram for SF₆ gas-density monitor system for an outdoor breaker. (Brown Boveri.)

10.2.5 Testing and Installation

Development and Design Testing of Circuit Breakers. Developing high voltage breakers requires attention to several different technical problems, including withstanding high voltages, short circuit interruption, continuous current capability, mechanical endurance, and environmental robustness. Testing programs are carried out to ensure that the circuit breaker is capable of withstanding these stresses. Test procedures for ac high-voltage circuit breakers are specified in IEEE C37.09¹¹.

High voltage. The breaker must carry current at high voltage, and be able to withstand transient surges at much higher levels (lightning strikes, for example). Typical test voltage levels are shown in Table 10-10.

Designing for these voltages requires specialized engineering software and knowledge. Dimensions are set for insulating gaps between contacts, and between live parts and the grounded surrounding structures (tanks, shields, etc.). Electromagnetic finite element analysis software is the main tool for this task. SF₆ breakers use pressurized SF₆ gas for insulation and arc quenching. This is because pressurized SF₆ insulates about 15 times better than air, meaning gaps can be much smaller for the same voltage and is vastly better for arc quenching (see Fig. 10-59).

High voltage testing requires “high voltage laboratory” capability with both power frequency “hi-pot” test capability, and also voltage surge (“lightning impulse” and “switching impulse”) test capability (see Fig. 10-73).

TABLE 10.10 Typical Test Voltages for Outdoor High-voltage ac Circuit Breakers

Rated maximum voltage kV	Power frequency withstand voltage (1min. dry) kV, rms	Full wave withstand (BIL) kV, peak
15.5	50	110
38	80	200
72.5	160	350
145	310	650
170	365	750
245	425	900
362	555	1300
550	860	1800
800	960	2050

Short-circuit interruption. The most important function of circuit breakers is to interrupt short-circuit currents. This is to protect generators, transmission lines, transformers, and other components of the transmission system. Typical short-circuit requirements of high voltage systems are 25 to 63 kA, though there is an increasing need for 80+ kA. During a short circuit (fault), the circuit breaker is subjected to both high currents and voltages at the same time. Designing for this capability involves engineering simulations and computational fluid dynamic analysis. Testing is difficult, as the momentary test power requirements can exceed even that available on the transmission grid. Therefore, so-called “synthetic” techniques are used for this testing. Synthetic testing involves separate sources for the high current and high voltage, and only combining them during a very brief window of time. This greatly reduces the power requirements of simulating short circuit interruption. A typical high-voltage synthetic power lab is shown in Fig. 10-74.

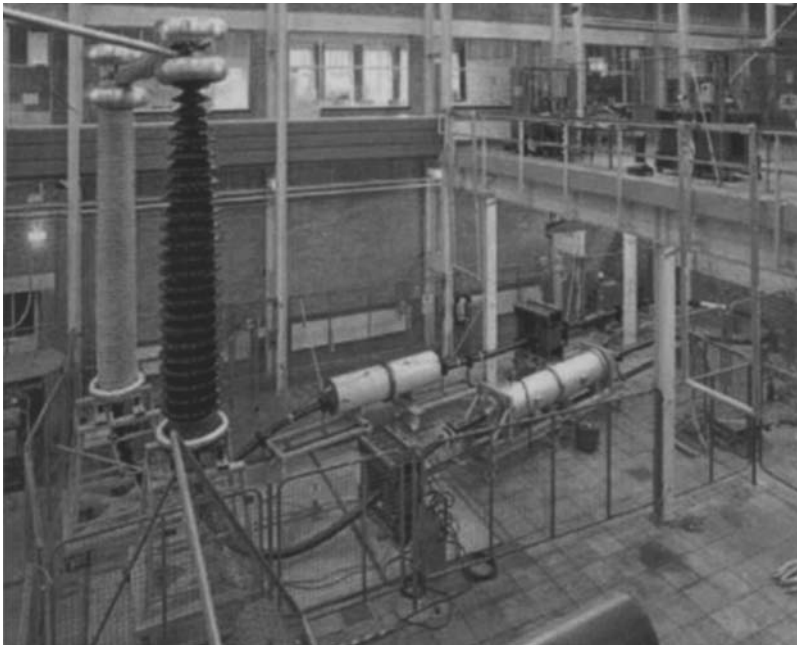


FIGURE 10-73 View of the B.V. KEMA high-voltage laboratory in Arnhem, The Netherlands. (Courtesy of B.V. KEMA.)

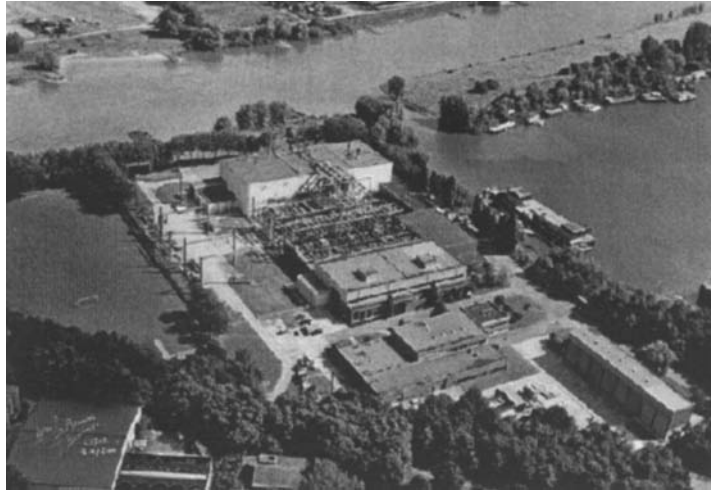


FIGURE 10-74 Aerial view of the B.V. KEMA high-power laboratory in Arnhem, The Netherlands. (Courtesy of B.V. KEMA)

The high current is typically supplied from dedicated “short-circuit generators,” which are specialized machines in the 1000 to 3000 short-circuit MVA class (see Fig. 10-75). High voltage is supplied from a “high voltage synthetic circuit,” which is a combination of capacitor banks, reactors, triggering, circuits, and computer controls (see Fig. 10-76). This synthetic circuit can produce a high voltage waveshape approximating real system recovery voltages.

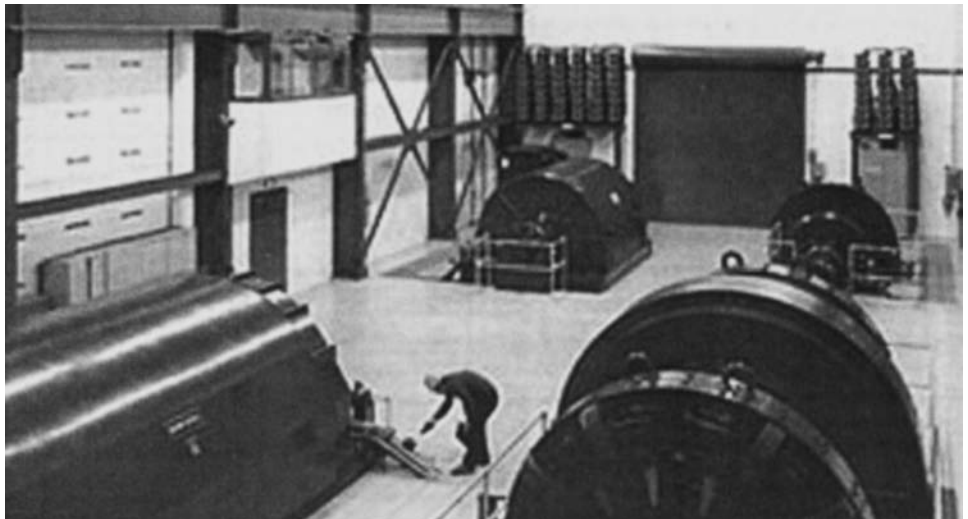


FIGURE 10-75 View of the KEMA-Powertest generator hall with 2,250 MVA and 1000 MVA short-circuit generators. (Courtesy of KEMA-Powertest, Chalfont, Pa. USA.)

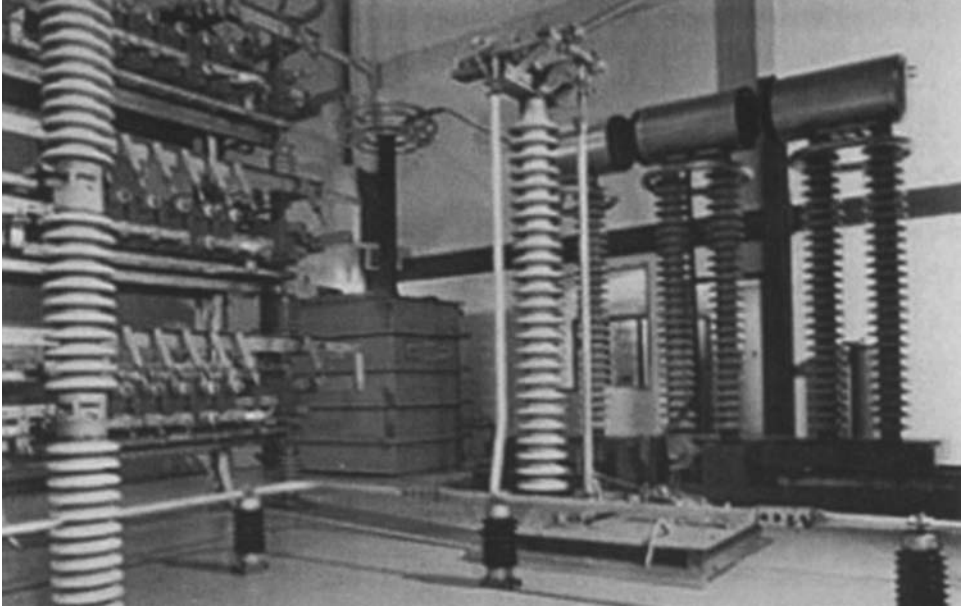


FIGURE 10-76 View of the KEMA-Powertest synthetic test circuit. (Courtesy of KEMA-Powertest, Chalfont, Pa. USA.)

In a real world, short-circuit interruption, a transient occurs following interruption which tries to reestablish the arc. This transient voltage must be synthesized by the test circuit and the required wave shapes differ widely between different breaker switching duties. A typical test involves initiating a short circuit with the high current circuit, and then at a “target” current zero simultaneously firing the high voltage synthetic circuit and switching out the high current circuit, (see Fig. 10-77).

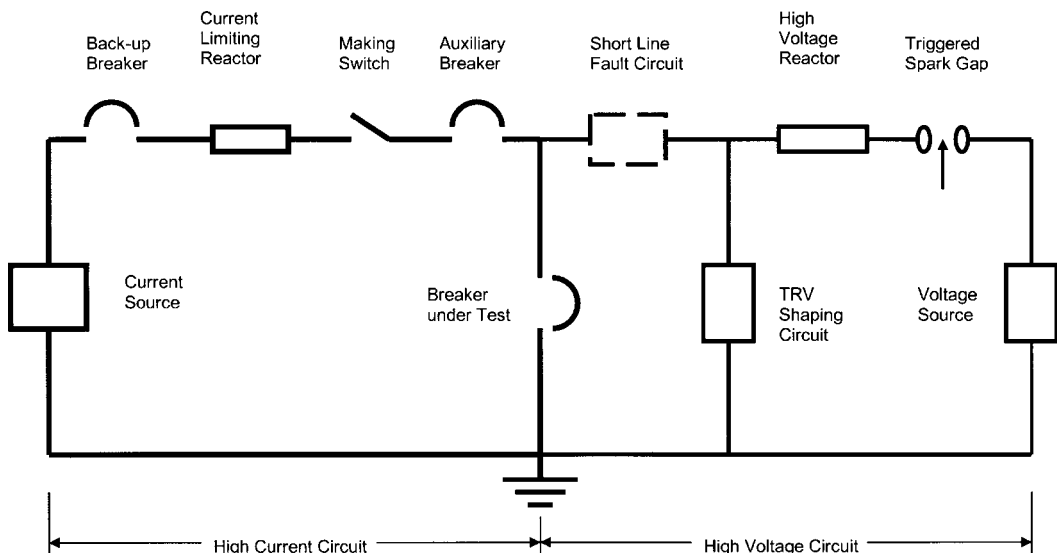


FIGURE 10-77 Parallel current injection test circuit.

The firing of the high voltage synthetic circuit provides correct short-circuit current dI/dt at the target current zero, and also provides the correct recovery voltage waveshape after successful interruption. Variations of the basic synthetic test circuit are used to simulate different switching and interrupting duties on the power system. Unit testing—testing only one interrupting break of a multi-break circuit breaker—is accepted by all current standards, with some qualification.

Continuous current capability. Circuit breakers must carry a rated continuous load current without exceeding allowable temperature limits. This is demonstrated by testing with a suitable test transformer and voltage/current regulator.

Mechanical endurance. Circuit breakers are intended to operate for many years in service without significant amounts of maintenance. They also must be capable of withstanding many switching operations over that life. Required testing to at least 2000 switching operations is required by standards, though circuit breakers may be required to meet higher values depending on the application and required ratings.

Environmental. Circuit breakers are applied in all temperature zones and in many severe seismic zones. Climatic testing is carried out to verify operation at temperature extremes and to verify the performance of heating systems, when required. For example, SF_6 circuit breakers may require that the insulating SF_6 gas remain heated to a temperature of at least -30°C so that liquification does not reduce the gas density. Reduction of the insulating gas density below allowable levels may reduce insulating and interrupting capability such that the circuit breaker can no longer meet its rated performance (see Fig. 10-72).

Seismic withstand capability is demonstrated either by finite element analysis (FEA) or by shaker table testing, depending on the voltage class. Typically, testing is required at 245 kV and above, with FEA being acceptable below 245 kV. Standard requirements for seismic specification, testing, and application are detailed in IEEE 693¹².

Production Tests. Every circuit breaker is subjected to a series of routine production tests primarily intended to prove design conformance and quality. These tests typically include high voltage power frequency tests (“hi-pot”), mechanical operation and timing tests, fluid/gas leakage tests (when applicable), and control circuit operation verification.

Installation and field tests. These tests are carried out on-site according to specific users or manufacturer’s instructions. Modern SF_6 breakers up to 245 kV are usually shipped fully assembled with a slight overpressure of SF_6 , thus eliminating evacuation procedures on-site.

Service and Maintenance. With rising system voltages, currents, interrupting ratings, and the requirement for uninterrupted power supply, circuit breaker reliability becomes more and more important. Besides influencing factors of (1) design, (2) quality assurance, and (3) testing, which are mainly a responsibility of the circuit breaker manufacturer, maximum attention must be paid to the maintenance during service. Maintenance instructions for different makes and types of circuit breakers may differ considerably in details and volume, but all strive to obtain maximum breaker reliability despite longer maintenance intervals, smaller inventories of exchange parts, and shorter maintenance hours. Efforts are made to find the easiest way of handling service without influencing neighboring gear and consequently obtaining the lowest service costs. Utility maintenance shafts, standardizing groups, and circuit breaker developers have taken into account these requirements. The various steps from oil breaker to air-blast and finally the SF_6 and vacuum breakers indicate a considerable minimizing of maintenance combined with maximum reliability.

10.2.6 Low-Voltage Circuit Breakers

Application. Air circuit breakers are used on dc and ac circuits for the protection of general lighting, power, and motor circuits.

Distinction is made between various protection classes and different service and ambient conditions. For selection of a breaker, type and rating, operating speed, selectivity with fuses, and high voltage must be taken into account.

Further consideration has to be given to severe or hazardous service conditions like tropical climate or marine- or explosion-proof installations.

Reference is made to IEEE C37.13¹³, C37.14¹⁴, and C37.17¹⁵; UL-489¹⁶; and ANSI C37.16¹⁷.

Ratings. Standard electrically and manually operated breakers are listed in ratings up to and including 5000 A ac and 12,000 A dc. Electrically operated breakers are available in higher current ratings for special applications. Standard breakers are rated on the basis of a temperature rise on the contacts and terminals not to exceed 50°C above an ambient of 40°C (class 90 insulation). Voltage ratings are 254 to 635 V ac and 250 to 3200 V dc.

The short-time current ratings are based on 3-phase symmetric short-circuit currents; the single-phase short-circuit current ratings are 87% of these values. For details, refer to the latest revisions of ANSI C37.16¹⁷.

Assembly Variations. The breakers are usually installed in a metal-enclosed cubicle for dead-front or drawout type of construction. Metal barriers between breakers and busbars provide increased safety in service.

Hand operation by means of a lever is common, even on large breakers. Electric operation by means of a solenoid or motor mechanisms for 48, 125, or 250 V dc, or 120 or 240 V ac is obtainable on all but the smallest sizes of breakers.

Breakers are supplied with an overcurrent trip mechanism which may be of the instantaneous or the time-delay type, or a combination of both. Trip devices are adjustable over a wide range of ratings. Other trip devices and arrangements may be used, for example, undervoltage trips, shunt trips connected to overvoltage, reverse current, or overcurrent relays.

Multiple-pole circuit breakers are commonly used in practically all capacities, one pole being used for each ungrounded line of a circuit, that is, a 2-pole breaker for a 3-wire grounded circuit or a single-pole breaker for a 2-wire grounded circuit.

Breakers can usually be equipped with auxiliary contacts, alarm contacts, push-button control, position indicator, and key interlock. The widely used drawout type of breaker may be moved into and locked in the connected, test, and disconnected positions and/or completely withdrawn.

Refer to the latest revisions of IEEE C37.13¹³, C37.14¹⁴, and C37.17¹⁵, and ANSI C37.16¹⁷.

Air Circuit Breaker. The usual construction of an air circuit breaker (Fig. 10-71) makes use of two fixed terminals mounted one above and the other in a vertical plane, which, when the breaker is closed, are bridged under heavy pressure by a bridging member operated by a system of linkages. Auxiliary and arcing contacts close before and open after the main contacts. The arcing contacts are easily renewable. The breaker is held closed by a latch which may be tripped electrically or mechanically. Modern breakers are trip-free.

Many breakers use a solid bridging member with spring-mounted self-aligning contacts. The contact surfaces are made of silver so that oxidation will not cause excessive resistance and overheating.

Arcing contacts of modern breakers use a silver-tungsten or copper-tungsten alloy which is arc-resistant. The secondary contacts, where used, are usually of copper or silver alloy.

Barriers between poles are generally furnished with breakers on ac and dc circuits 250 V and above, and special arc chutes, quenchers, or deionizing chambers are also used throughout the available lines of air circuit breakers. These devices are made in different forms by different manufacturers and serve to improve the interrupting performance of the breaker and to shorten the arcing time.

Molded-Case Circuit Breaker. This circuit breaker is completely enclosed within a ruggedly constructed molded case of insulating material. It has received wide acceptance in the industry and is particularly adaptable in large buildings and industrial plants. The molded-case circuit breaker, in

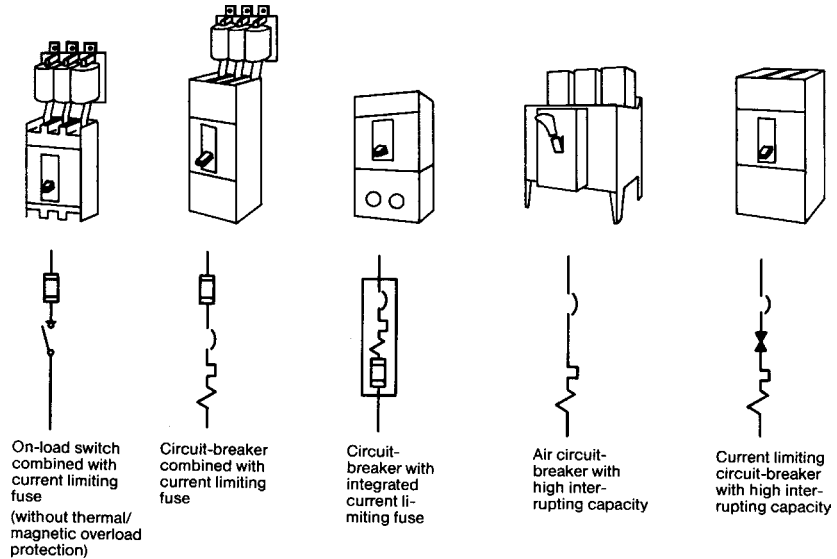


FIGURE 10-78 Methods of current-limiting in low-voltage circuits.

smaller sizes, is adaptable in home lighting circuits where convenience of automatic protection with manual reset of the breaker is desired.

Continuous current ratings range from 15 to 4000 A; the interrupting ratings are from 5 to 45 kA within the standard range. High interrupting ratings up to 200 kA are available.

For details of technical data, application, and accessories, refer to manufacturers' catalogs.

Current-Limiting Breaker. Low-voltage switchgear is more frequently connected to systems with high or extrahigh short-circuit currents. The standard-range circuit breaker cannot satisfy these requirements. Figure 10-78 outlines different ways to solve the problem. The current-limiting circuit breaker with high interrupting capacity offers a technically sound and economical solution.

Current-limiting breakers operate extremely fast. Interruption takes place within the first half cycle of short-circuit current, so the peak value is not reached. The total break time is less than 5 ms. Figure 10-79 illustrates the current curve, and Fig. 10-80 shows the current-limiting characteristic of a 100-A breaker. With an initial symmetric short-circuit current of 40 kA, the prospective peak value would be 82.5 kA, considering a dc component of 50% and power factor of 0.25. By using a current-limiting breaker, the peak value is limited to about 20 kA. The mechanical stress on the insulation is thus reduced considerably. The contacts in current-limiting circuit breakers are so arranged that the interruption is assisted by the electrodynamic action of the short-circuit current. The higher the short-circuit current, the faster the interruption takes place.

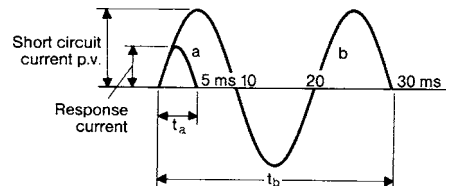


FIGURE 10-79 Current wave (a) with limitation, and (b) without limitation; t_a = total break time a ; t_b = total break time b .

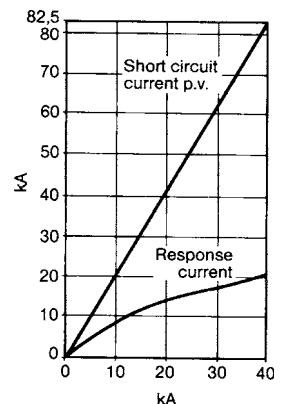


FIGURE 10-80 Current-limiting capability of a motor-protection circuit breaker, 100-A continuous current rating.

Because of the short opening time, the current-limiting circuit breaker, with suitable accessories, can be used to protect power electronic components. Rectifier circuits omitting fuses, for example can be built in this way.

10.2.7 High-Voltage Circuit Breakers

Application. High-voltage circuit breakers have been applied from 1 kV to up to 1100 kV. They are available in either live tank or dead tank design, and may incorporate various insulating and interrupting media as discussed in Sec. 10.2.1.

In today's market, SF₆ circuit breakers dominate above 38 kV, with vacuum circuit breakers being dominant in the "medium" voltage range between 15 and 38 kV. Air magnetic circuit breakers are also common up to 15 kV. Historically, oil circuit breakers were prevalent in these voltage ranges. Even though oil circuit breakers are out of production today, many remain in service.

Indoor breakers in the United States have been historically magnetic air or air-blast types. Today vacuum circuit breakers dominate for indoor application, but there are a few SF₆ types.

For guidance in circuit breaker selection and application, refer to the latest revisions of IEEE C37.12¹⁸, C37.010⁶, C37.011⁷, and C37.012⁸.

Ratings. Standard short circuit currents range from 12.5 to 63 kA, with some applications requiring 80 kA. Commercially available continuous current ratings range from 600 to 5000 A. Preferred ratings are defined in IEEE C37.06³.

Ratings differentiate between indoor and outdoor service. Preferred ratings are further established for capacitive current switching, dielectric withstand and external insulation, transient recovery voltage capabilities, switching surge factors for line closing, control voltages, reclosing times, and operation endurance capabilities.

Refer to IEEE C37.04² and C37.06³ for the rating structure and preferred ratings.

Oil Circuit Breakers. Oil circuit breakers are out of production today, but many remain in service. These breakers were classified as either dead tank "bulk oil" circuit breakers, or as live tank "minimum oil" circuit breakers. Oil circuit breakers use oil as both an arc quenching and insulating medium, with dead tank "bulk oil" designs using oil as the primary insulation to ground, within a grounded tank.

Dead tank "bulk oil" circuit breakers consist of a steel tank partly filled with oil, through the cover of which are high voltage entrance bushings. Contacts at the bottom of the bushings are bridged by a conducting crosshead carried by a wood or composite lift rod. The breaker typically opens by spring action, separating the interrupting contacts and also further separating an isolation break below the contact system. Accelerating springs are used to increase the speed of opening. In some designs, the crosshead is opened with a rotary motion by springs. Breakers with 3 poles in one tank were made up to 69 kV. Higher voltages had separate tanks for each pole. Figure 10-53 shows a typical dead tank "bulk oil" circuit breaker and Fig. 10-81 shows a typical interrupter.

Minimum oil circuit breakers were developed mainly in Europe to reduce the quantity of oil in circuit breakers. They were manufactured for indoor applications up through 38-kV and outdoor applications up through 800-kV, but were mainly used in the medium voltage range for indoor service. The layout of a medium voltage minimum oil circuit breaker is shown in Fig. 10-82.

Vacuum Circuit Breaker. Progress in high-vacuum technology and breaker development, combined with improved manufacturing and testing methods, has opened a growing area for vacuum breaker application, concentrating, but not limited to voltages up to 38 kV, continuous current ratings up to 3000 A, and covering all standard interrupting ranges. The principal design of a vacuum interrupter is shown in Fig. 10-83.

Two contacts are mounted on an insulating envelope from which virtually all air has been evacuated. One contact is stationary, the other movable. Vacuum interruption has the inherent advantage of moving a lightweight contact only a very small distance in an almost perfect dielectric medium. This results in safe, quiet, and fast switching or interruption of load or fault currents.

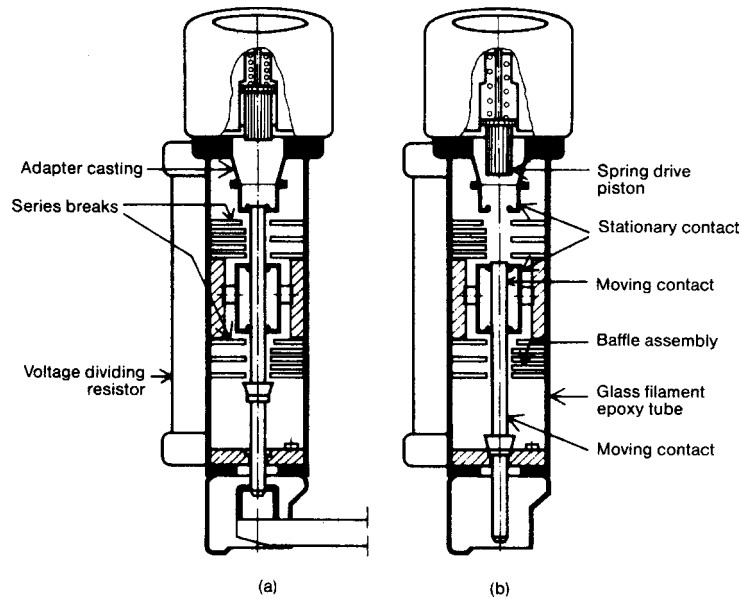


FIGURE 10-81 Details of a 161-kV outdoor oil circuit breaker interrupter: (a) closed position; (b) open position.

The moving contact is opened up to full gap distance by means of a driving mechanism. A metal-vapor arc discharge thus occurs in the contact gap through which the current flows until the next current zero. The arc is quenched at current zero.

The metal-vapor plasma is fully deionized within a few microseconds by diffusion and recombination so that the conduction path very quickly recovers its dielectric strength. Figure 10-84 shows details of a horizontal-drawout vacuum circuit breaker. One or more interrupters may be utilized in

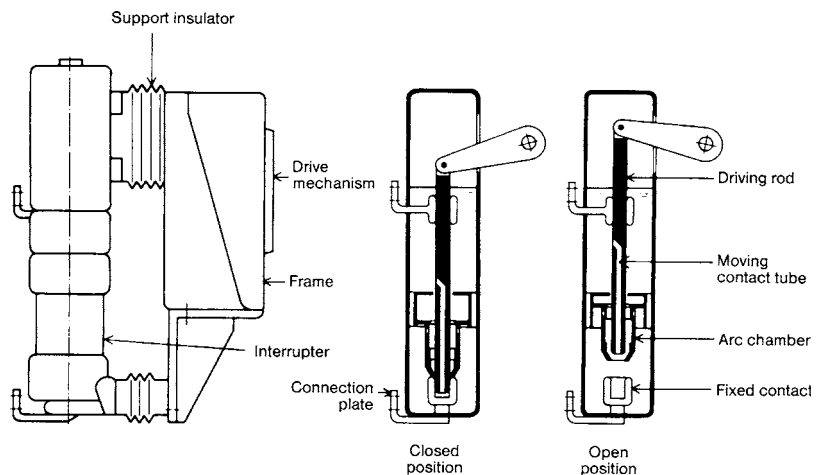


FIGURE 10-82 Outline and interrupter details of a 15-kV, 3-pole minimum-oil circuit breaker. (Courtesy of ABB T&D Company, Inc.)

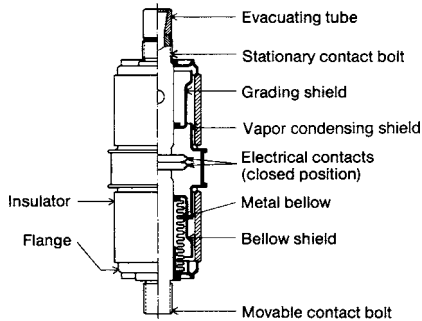


FIGURE 10-83 Partial section of vacuum interrupter 23 kV, 2000 A, 21 kA. (ABB T&D Company, Inc.)

series per pole. Vacuum interrupters may additionally be protected against outside influences by an insulating casing. They may also be fitted with hand- or motor-charged stored-energy-operated mechanisms.

Because of their fast closing and opening times, vacuum circuit breakers are particularly suitable for autoreclosure and synchronizing duty. Breaking of the short-circuit currents with very steep initial rise of transient recovery voltage is possible due to restoration of the dielectric strength of the contact gap within a few microseconds. The steep rise of dielectric strength over the whole current range offers a high capacitive-current-switching capability. Switching of unloaded transmission lines and cables can therefore reliably be performed.

Magnetic Air Circuit Breaker. Magnetic air circuit breakers are no longer manufactured. This type of circuit breaker is usually stored-energy mechanism-operated and interrupts the main circuit in the normal atmosphere under the influence of a strong magnetic field which acts to force the arc deep into a specially designed arc chute (see Fig. 10-85). Solenoid operating mechanisms are available. The arc chute cools and lengthens the arc to a point where the arc cannot be maintained by the voltage of the system, and interruption is accomplished. The zone between the main contacts is clear of ionized air by the time interruption is obtained in the arc chute, and so restiking at this point is no problem. Since the magnetic effect is not great at low currents such as small load, transformer magnetizing, and cable-charging current, all designs use an air-pump “puffer” actuated by the operating mechanism that blows a blast of air across the arc and thereby ensures its entering the arc chute and giving rapid interruption at the low-current values also. When the circuit breaker is opened, the arc transfers from the main arcing contacts to fixed arc runners which are within the arc chute. The magnetic field is produced by coils in the main-current circuit, in some cases wound around a magnetic core which magnetizes soft-iron plates in the sides of each arc chute. Some designs do not require an iron core.

Magnetic air breakers were available in any of the ratings of Table 2 of ANSI Standard C37.06-1987 (or earlier) through 15- kV. All were designed for use in metal-clad enclosures. Figure 10-86 shows the horizontal-drawout type of breaker in metal-clad enclosure. Although the design shown is for indoor use only, the same circuit breakers are placed in weatherproof housings for outdoor

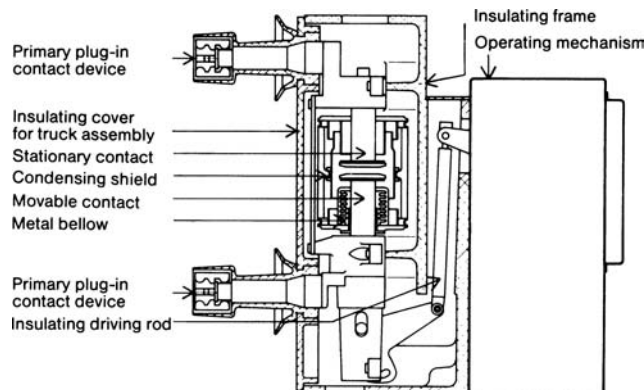


FIGURE 10-84 Outline and interrupter details of a 15-kV horizontal-drawout vacuum circuit breaker 2000A, 28 kA. (ABB T&D Company, Inc.)

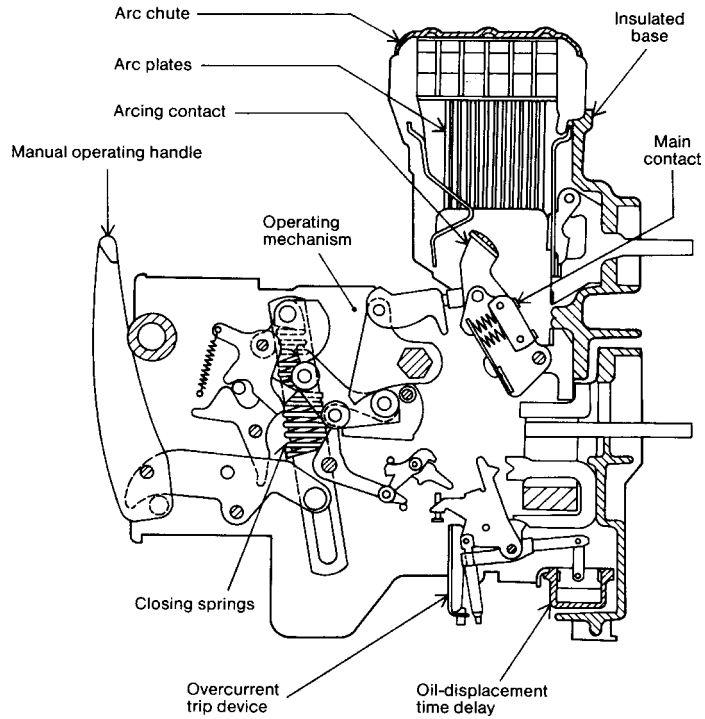


FIGURE 10-85 Typical low-voltage air circuit breaker with magnetic air chutes; breaker in the open position.

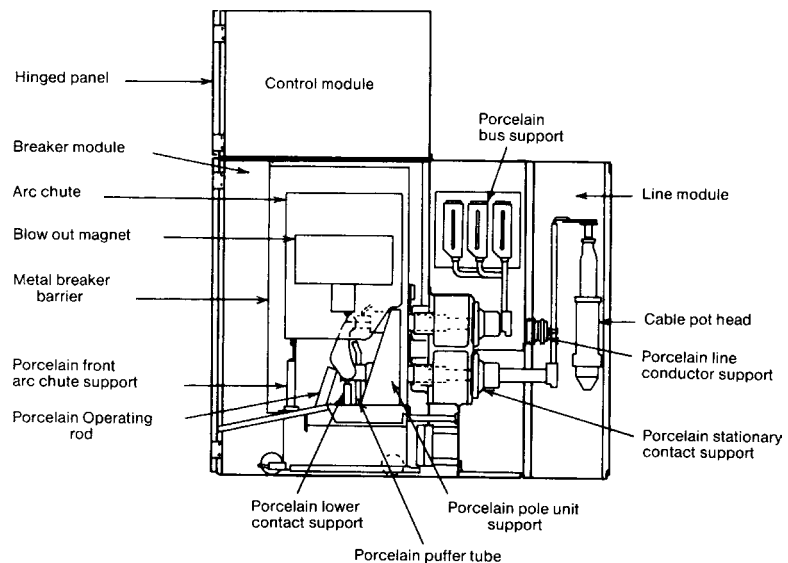


FIGURE 10-86 Horizontal-drawout, metal-clad magnetic circuit breaker in service position.

service. When they are so used, suitable heaters are put in the housings to avoid internal moisture condensation.

Air-Blast Circuit Breakers. Air-Blast circuit breakers are no longer manufactured. These breakers fulfilled the heavy-duty requirements of circuit breakers in high-voltage systems. They have been used to provide the indoor ratings up to 38 kV. They were, however, mainly used in outdoor applications up to 800 kV. Today they have been replaced by SF_6 technology at most ratings.

Air-blast circuit breakers have been used for special applications as (1) generator breakers with continuous current ratings of up to 42 kA and higher, (2) furnace breakers with an extra high number of switching operations (20 to 50 duty cycles per day), and (3) extra high interrupting currents. Air-blast circuit breakers were usually fixed-mounted, but a variety of breaker types were available truck-mounted for application in drawout metal-clad switchgear. All air-blast circuit breakers make use of dry and clean air compressed to a certain pressure, which may differ for the various make and types of breakers. The compressed air is used to operate the breaker as well as to serve as the medium for arc quenching and insulation.

Continuous current ratings up to 5000 A were possible. Total breaking time of 2 cycles (from energizing of trip coil until arc extinguishing) was standard; special designs may allow for even shorter breaking time. Some 69-kV breakers are equipped with sequential isolators, but the bulk of designs did not integrate the isolator to form part of the circuit breaker. Some older designs employed separate chambers for opening and closing operation, but later air-blast breakers perform opening and closing with the same contact system. Closing resistors and/or, with some designs, opening resistors were often used. Equal voltage distribution over the multiple breakers of one pole was usually achieved by parallel capacitors.

Generator Circuit Breakers. Generator circuit breakers represent another class rated for very high continuous currents and short-circuit currents, typically at generator voltages. Generator breakers are incorporated into generator bus ducts and can include other switchgear components for measuring current, detecting faults, and grounding.

Generator breakers are available up to 50 kA nominal current and up to 220 kA interrupting current. Two technologies are employed—air blast at the higher ratings (see Fig. 10-87) and SF_6 self-blast at the lower and medium power levels (up to 120 kA). For nominal currents above 20 kA, the generator breaker is usually equipped with a forced cooling system, using water, for example. Generator breakers have been available since the 1960s.

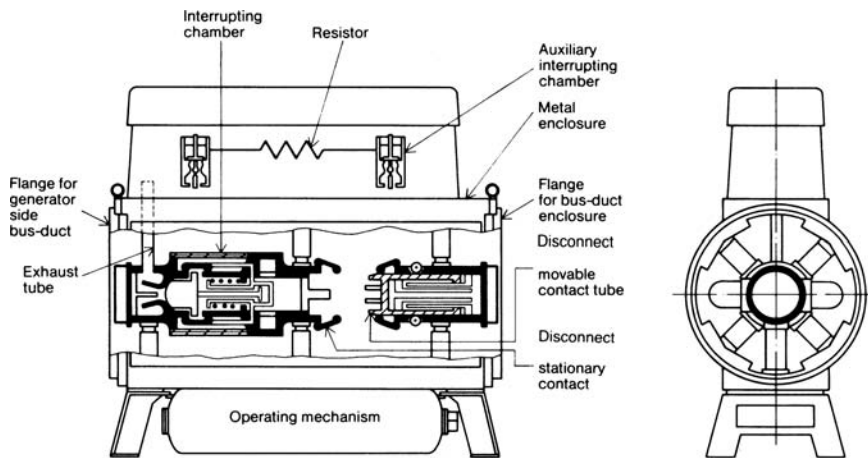


FIGURE 10-87 Outline and interrupter details of a generator air-blast circuit breaker-type DR, 36 kV, up to 50 kA with forced cooling, 200 kA.

Advantages of using generator breakers include the following:

Reduced station cost by eliminating station transformers and increasing station layout flexibility. Simplification of operation, especially during commissioning and recommissioning; this is because the generator can be handled as a separate unit, isolated from the main and unit transformers.

Fault protection between the generator and transformer. Two zones of protection are created and generator faults are cleared by the opening of the generator breaker alone.

Unbalanced load protection of the generator.

Protection of the generator from transformer faults.

Reliability/availability increase.

Historically, generator circuit breakers have been of air-blast design with pneumatic operators. This is the technology still used today for large nuclear and fossil fuel power plants (up to 1500 MW), and large pumped storage installations. The design has a tubular housing and is horizontal.

Newer designs utilize SF_6 self-blast technology and hydraulic operators. These are rated for application to smaller power plants (gas turbine/cogen, for example) from 60 to 400 MW and smaller pumped storage installations.

SF_6 Circuit Breakers. SF_6 gas has proven to be an excellent arc quenching and insulating medium for circuit breakers. SF_6 is a very stable compound, inert up to about 500°C , non-flammable, non-toxic, odorless, and colorless. At a temperature of about 2000K SF_6 has a very high specific heat, and high thermal conductivity, which promotes cooling of the arc plasma just before and at current zero, and thus facilitates quenching of the arc. The electronegativity behavior of the SF_6 , that is, the property of capturing free electrons and forming negative ions, results in high dielectric strength and also promotes rapid dielectric recovery of the arc channel after arc quenching. SF_6 breakers are available for all voltages up to 1100 kV, continuous currents up to 5000 A for conventional breakers (higher for generator breakers), and short-circuit interruption up to 80 kA.

SF_6 breakers of the indoor type have been incorporated into metal-clad switchgear (see Fig. 10-88). Outdoor designs include both dead tank (see Fig. 10-54) and live tank circuit breakers (see Figs. 10-56 and 10-57).

Over the years, SF_6 circuit breakers have reached a high degree of reliability; thus they can cope with all known switching phenomena. Their closed-gas system eliminates external exhaust during switching operations and thus perfectly adapts to environmental requirements. Their compact design considerably reduces space requirements and building and installation costs. In addition, SF_6 circuit breakers require very little maintenance.

All ratings are economically satisfied by the modular design. Each pole is equipped with one or more interrupters; stored energy, spring, hydraulic, or pneumatic driving mechanisms are provided for each pole or 3-pole unit. Gas-density monitors are standard.

Figure 10-89 illustrates the opening sequence of a typical puffer breaker. In the closed position, the current flows over the continuous current contacts and the complete volume of the breaker pole is under the same pressure of SF_6 gas.

The precompression of the SF_6 gas commences with the opening operation. The continuous current contacts separate and the current is transferred to the arcing contacts.

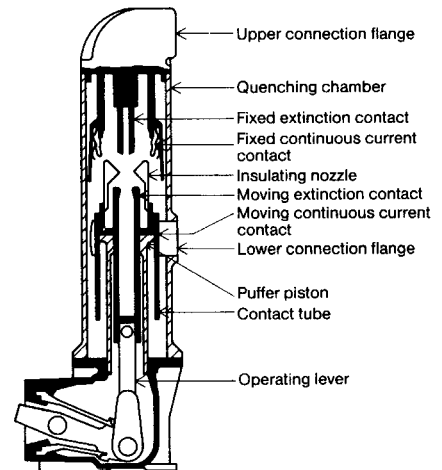


FIGURE 10-88 Section of a SF_6 puffer-piston indoor circuit breaker, 23 kV.

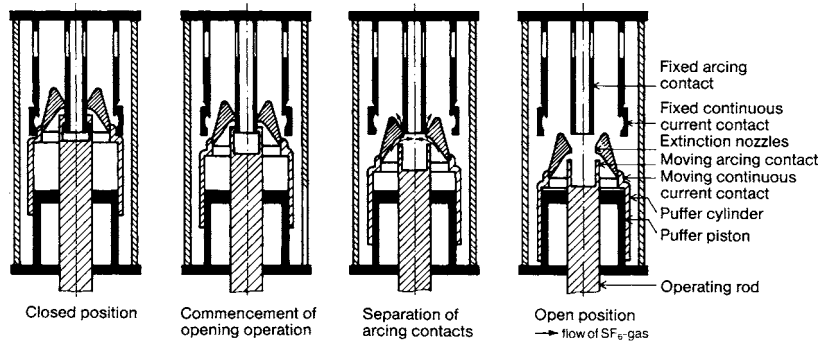


FIGURE 10-89 Principle of SF_6 puffer-type interrupter showing four positions during opening operation.

At the instant of separation of the arcing contacts, the pressure required to extinguish the arc is reached. The arc produced is drawn and at the same time exposed to the gas, which escapes through the ring-shaped space between the extinction nozzle and the moving arcing contact. The escaping gas has the effect of a double blast in both axial directions.

Until the open position is reached, SF_6 gas flows out of the puffer cylinder. The existing over-pressure maintains stability of the dielectric strength until the full value of the open contacts at the rated service pressure is reached.

The *self-blast principle* of interruption is illustrated in Fig. 10-90. In the case of high-current interruption, arc energy heats the gas, resulting in a pressure rise in the static volume (heating volume) V_1 . This pressure then quenches the arc at an ensuing current zero. In the low-current case an auxiliary puffer (volume, V_2) generates sufficient pressure for interruption. Necessary force requirements for the mechanical system are therefore drastically reduced.

All ancillary equipments, including the oil pump and accumulator associated with the drive, form a modular assembly that is mounted directly on the circuit breaker, thus eliminating installation of piping on the site. The *metal-enclosed GIS breaker* is provided with the necessary items to fit into the substation arrangement (see Fig. 10-91). The main equipment flanges of the breaker are fitted with contact assemblies to accept the isolator moving contacts. Other equipment modules can be coupled to the same flanges. On the fixed-contact end of the circuit breaker, provision is made for coupling two modules, facilitating the mounting of an extension module to connect the second busbar isolator.

Dead tank SF_6 breakers typically employ gas-filled *bushings*, illustrated in Fig. 10-55. Such bushings are usually integral to the circuit breaker itself and are not interchangeable with other apparatus bushings. Electrical grading is provided by a lower throat shield. Ring-type bushing current transformers are located at the base of the bushing. Potential taps are not generally available in SF_6 bushings because of the lack of a capacitive grading structure.

Porcelain alternatives, such as composites, have been used to provide greater safety (explosion resistance), easier handling (lighter and nonbrittle), seismic performance (lighter and stronger), and pollution performance.

Current transformers (CTs) for dead-tank breakers are of the ring-type bushing design. Outdoor breakers of the live-tank layout are generally provided with freestanding CTs of the paper-oil-insulated or SF_6 design (see Fig. 10-57).

For oil-filled CTs, hermetical seal of oil is either of the fixed design with gas cushion or of the pressure-free bellow type. Up to six magnetic cores can be provided per CT unit, generally in multiratios for 5- or 1-A secondary by means of secondary taps. Primary-current ratings up to 2000 A normally employ the wound-type design with two or more turns. Higher primary currents up to 6000 A require the inverted or head design, with a straight tube as single-turn primary winding and the core

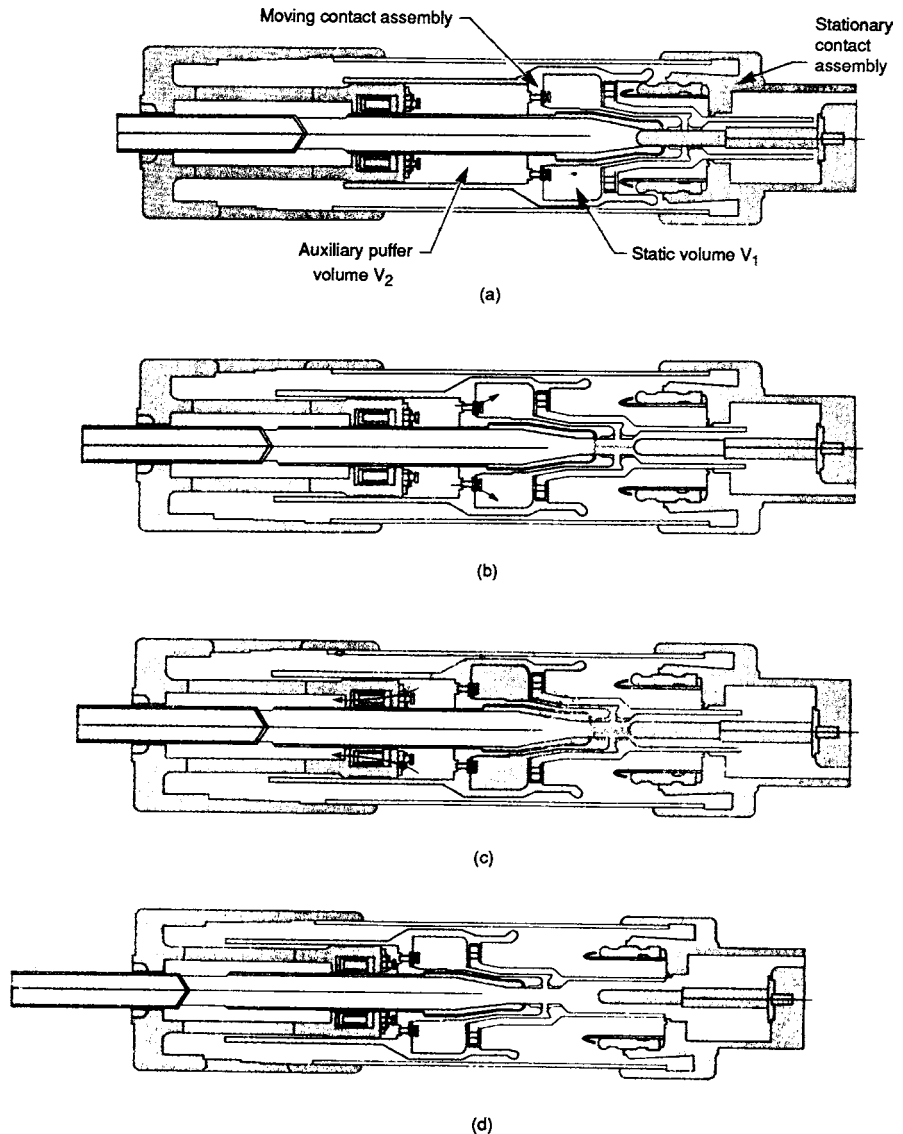


FIGURE 10-90 Self-blast principle of interruption: (a) full-closed position; (b) low-current interruption; (c) high-current interruption; (d) full-open position.

and secondary-winding assembly arranged at the CT top to limit temperature rise and to increase the mechanical withstand capability of the CT. The latter design has its full main insulation on the secondary winding.

Freestanding CTs are available for all output and accuracy requirements for modern system relaying and measuring for voltages up to 800 kV. For the upper voltage ranges, freestanding CTs are normally provided with separate potential layers. The CTs are generally dimensioned for the same dielectric and mechanical characteristics chosen for the related circuit breaker.

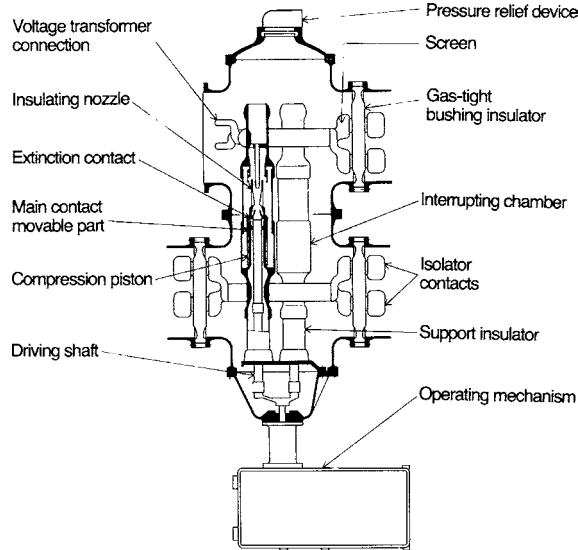


FIGURE 10-91 Section of a 145-kV SF₆ circuit breaker for gas-insulated substation (GIS) type ELK.

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4. ANSI C37.06, *Standard for AC High-Voltage Circuit Breakers Rated on a Symmetrical Basis-Preferred Ratings and Related Required Capabilities* (Versions of C37.06 prior to 2003 were done by NEMA working groups. In 2003, NEMA transferred ownership of C37.06 to IEEE).
5. IEEE C37.100.1, (This document was being balloted at the time this chapter was written).
6. IEEE C37.010, *Application Guide for AC High-Voltage Circuit Breakers*.
7. IEEE C37.011, *Application Guide for Transient Recovery Voltage for AC High-Voltage Circuit Breakers*.
8. IEEE C37.012, *Application Guide for Capacitance Current Switching for AC High-Voltage Circuit Breakers*.
9. IEEE C37.015, *Application Guide for Shunt Reactor Switching*.
10. IEEE C37.7-1960,
11. IEEE C37.09, *Standard Test Procedure for AC High-Voltage Circuit Breakers*.
12. IEEE 693, *Recommended Practice for Seismic Design of Substations*.
13. IEEE C37.13, *Standard for Low-Voltage AC Power Circuit Breakers Used in Enclosures*.
14. IEEE C37.14, *Standard for Low-Voltage DC Power Circuit Breakers Used in Enclosures*.
15. IEEE C37.17, *Standard for Trip Devices for AC and General Purpose DC Low-Voltage Power Circuit Breakers*.
16. UL-489, *Standard for Safety Molded-Case Circuit Breakers, Molded-Case Switches, and Circuit-Breaker Enclosures*.
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10.3 SWITCHGEAR ASSEMBLIES

By JEFFREY H. NELSON, MICHAEL W. WACTOR and TED W. OLSEN

Definitions of terms used in this section can be found in the IEEE standards and application guides referenced in this section and/or in the *IEEE Authoritative Dictionary of Terms*. The term “low voltage” as used in this section refers to rated voltages up to 1000 V ac and 3200 V dc. The term “medium voltage” as used in this section refers to rated voltages above 1000 V ac up to 38 kV ac.

Switchgear assemblies cover a wide range of low-voltage and high-voltage structures that are generally factory assembled and are divided into the following main groups: (1) metal-enclosed low-voltage power circuit breaker switchgear, (2) medium-voltage metal-clad switchgear, (3) metal-enclosed interrupter switchgear, (4) metal-enclosed bus, and (5) switchboards. ANSI/IEEE C37.20.1¹, C37.20.2²,

C37.20.3³, C37.23⁴ and NEMA PB-2⁵ apply. Any of these equipment types may be rated as “arc resistant metal-enclosed switchgear” by successfully meeting the requirements of ANSI/IEEE C37.20.7⁶.

10.3.1 Metal-Enclosed Low-Voltage Power Circuit Breaker Switchgear

Metal-enclosed low-voltage power circuit breaker switchgear indicates a design which contains low-voltage ac or dc power circuit breakers in individual grounded metal compartments. The circuit breakers can be either stationary or drawout; manually or electrically operated; fused or unfused; and either 3-pole, 2-pole or single-pole, construction. The switchgear may also contain associated control, instruments, metering, protective and regulating equipment as necessary. Definitions, ratings, design and production tests, construction requirements, and guidelines for application, handling, storage, and installation are covered in IEEE C37.20.1¹.

Low-voltage metal-enclosed switchgear is typically installed in industrial plants, utility and cogeneration facilities, and commercial buildings for the protection and distribution of power for loads such as lighting, machinery, motor control centers, elevators, air conditioning, blowers, compressors, fans, pumps, and motors. Low-voltage switchgear is available in ac ratings up to 635 V and 5000 A continuous and in dc ratings up to 3200 V and 12000 A continuous. Short-circuit current ratings are available up to 200 kA.

10.3.2 Metal-Clad Switchgear

The term “metal-clad switchgear” indicates a design providing metal barriers between primary sections of adjacent vertical sections and between major primary sections of each circuit. Primary sections comprise the bus compartment, the primary entrance compartment, the removable element compartment, the voltage transformer(s) compartment, and the control power transformer(s) compartment. Low-voltage control equipment such as metering, relays, instruments, and controls are located in compartments separate from the primary voltage components. To minimize the possibility of communicating faults between primary sections, the barriers between primary sections shall have no intentional openings. Barriers may be provided to segregate the voltage transformers for each polyphase circuit but not to segregate them individually. Where buses penetrate barriers, suitable bushings or other insulation is required. Definitions, ratings, design and production tests, construction requirements, and guidelines for application, handling, storage and installation are covered in IEEE C37.20.2².

Circuit breakers are generally the vacuum type, although air-magnetic circuit breakers were used for many years. Circuit breaker disconnection is accomplished by horizontal-drawout design, illustrated in Figs. 10-92 and 10-93, respectively. Interlocks are provided in metal-clad assemblies to prevent disconnecting or connecting the circuit breaker while in the closed position and to prevent breaker operation while moving between disconnected and connected position or vice versa. The metal-clad assembly is equipped with shutters to protect personnel from coming in contact with the high-voltage circuits when the circuit breaker is removed from the cubicle. A circuit breaker test position is standard to allow breaker control with the main contacts (primary disconnecting devices) removed from the primary circuit, but maintaining auxiliary and ground contacts between cubicle and breaker truck.

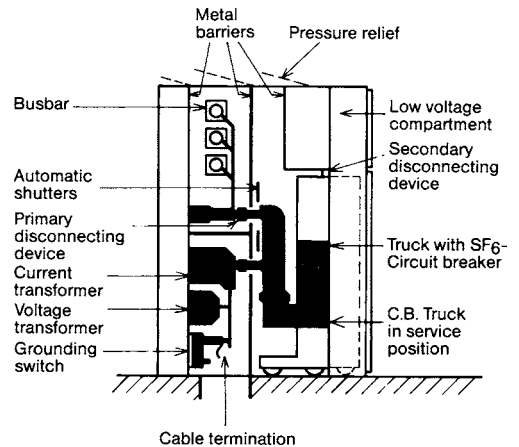


FIGURE 10-92 Side view of a 15-kV metal-clad switchgear unit with horizontal-drawout circuit breaker, interchangeable either minimum oil, SF₆ or vacuum design of equal rating.

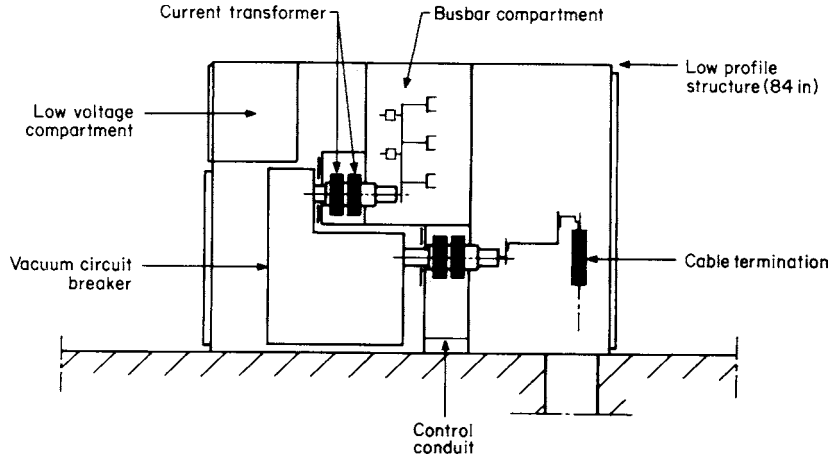


FIGURE 10-93 Side view of a 38-kV metal-clad switchgear unit with horizontal-drawout vacuum circuit breaker, type HKV, up to 3000 A, fan cooled, 22 kA.

Metal-clad switchgear is used for low- and medium-capacity circuits, for indoor and outdoor installations with nominal voltages of 2.4 to 34.5 kV and continuous current ratings typically up to 3000 A. Short-circuit withstand current ratings of the switchgear should equal the ratings of the circuit breaker used.

10.3.3 Metal-Enclosed Interrupter Switchgear

Metal-enclosed interrupter switchgear assemblies include the following equipment as required: interrupter switches, bare bus and connections, selector switches, power fuses (current-limiting or noncurrent-limiting), control and protective equipment, instrumentation, meters, and instrument transformers. The interrupter switches and power fuses may be stationary or removable (drawout). When switches and fuses are removable, mechanical interlocks are provided for proper operating sequence. Also, automatic shutters are provided which cover primary circuit elements when the removable device is in the disconnected, test or removed position.

Definitions, ratings, design and production tests, construction requirements, and guidelines for application, handling, storage, and installation for metal-enclosed interrupter switchgear are covered in IEEE C37.20.3³.

Metal-enclosed interrupter switchgear is typically used in industrial or institutional environments where continuous load currents are low and frequent switching is not required. Interrupter switches will interrupt load currents up to their rated continuous current capability. Fuses can be installed to provide short-circuit protection. For example, if the interrupter switchgear is connected to other switching equipment fuses can be installed in the connection between the two to prevent an interruption of one assembly for a fault in the other assembly.

Typical applications for interrupter switchgear include main service disconnect, transformer primary and secondary switching, medium voltage switchgear primary and feeder circuit switching. The switching device may be manually operated or motor operated. Motor operated designs are often applied in an automatic transfer scheme.

Metal-enclosed interrupter switchgear is typically available in ac ratings above 1 kV to up to 38 kV and 2000 A continuous current. Short-circuit withstand ratings have to be equivalent to the ratings of the switching and protective equipment used or to the rating of the current transformers used.

10.3.4 Metal-Enclosed Bus

Metal-enclosed bus is an assembly of rigid conductors with associated connections, joints and insulating supports with a grounded metal enclosure. Metal enclosed buses have three basic types of construction: (1) nonsegregated-phase, (2) segregated-phase, and (3) isolated phase.

Rated voltages of ac metal-enclosed bus assemblies range from 635 V through 38 kV, and dc metal-enclosed bus assemblies range from 300 through 3200 V. Definitions, service conditions, ratings, testing, construction requirements, and application guidelines for metal-enclosed bus are covered in IEEE C37.23⁴. An informative guide for calculating losses in isolated-phase bus is also included.

Nonsegregated-Phase Metal-Enclosed Bus.

Nonsegregated-phase metal-enclosed bus is a type of design in which all phase conductors, with their associated connections, joints, and insulating supports, are enclosed in a common metal housing without barriers between phases, see Fig. 10-94. When associated with metal-clad switchgear, the phase conductors of a non-insulated bus assembly entering the switchgear assembly and connecting to the switchgear bus shall be covered with insulating material equivalent to the switchgear insulation system. Enclosures that are totally enclosed are preferred, but ventilated enclosures can be provided in indoor applications.

Nonsegregated-phase metal-enclosed bus is utilized on circuits which require higher reliability than can be obtained with the application of power cables. Typical applications are the connections between transformers and switchgear assemblies, connections from switchgear assemblies to rotating apparatus, tie connections between switchgear assemblies, connections between motor control centers and large motors, and as main generator leads for small generators.

Preferred continuous self-cooled current ratings for nonsegregated-phase are available up to 12,000 A for 635 V ac and all dc voltage ratings, 6000 A for 4.75 through 15.5 kV, and 3000 A above 15.5 through 38 kV. Short-time withstand current ratings up to 85 kA rms symmetrical are available for ac ratings, and up to 120 kA for dc ratings.

Segregated-Phase Metal-Enclosed Bus.

Barriers may be installed between the phase conductors to segregate the conductors and the assembly is then referred to as “*segregated-phase metal-enclosed bus*,” see Fig. 10-95. This design is also used on circuits which require a higher degree of reliability.

Segregated-phase bus is primarily used as generator leads in power plants, but it is also applied in heavy industrial environments and as tie connections in metal-enclosed substations.

Preferred continuous self-cooled current ratings for segregated-phase are available up to 12,000 A for 635 V ac and all dc voltage ratings, 6000 A for 4.75 through 15.5 kV, and 3000 A above 15.5 through 38 kV. Short-time withstand current ratings up to 85 kA rms symmetrical are available for ac ratings, and up to 120 kA for dc ratings.

Isolated-Phase Metal-Enclosed Bus. “*Isolated-phase metal-enclosed bus*” is a type of design in which each phase is enclosed in an individual metal housing, and an air space is provided

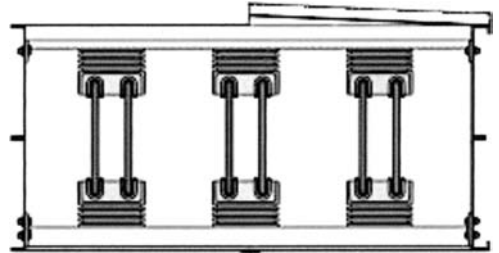


FIGURE 10-94 Typical nonsegregated-phase metal enclosed bus. (Courtesy of Powell Industries, Inc.)

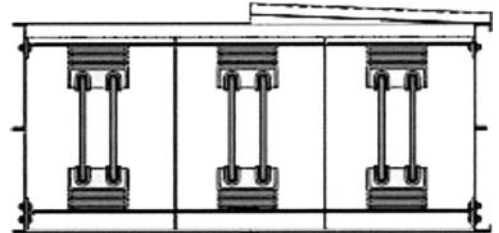


FIGURE 10-95 Typical segregated-phase metal enclosed bus. (Courtesy of Powell Industries, Inc.)

between the housings. It is considered to be the safest, most practical, and most economical way of preventing phase-to-phase short circuits by means of construction methods. The bus may be self-cooled or force-cooled by circulating air or liquid. Definitions, ratings, design and production tests, construction requirements, and application guidelines for metal-enclosed bus are covered in IEEE C37.23⁴.

Briefly, the isolated-phase bus duct has the following features:

1. Proof against contact; locked electrical premises not necessary
2. Faults only in the form of ground faults; protection against fault spreading to more than one phase
3. Field forces, static and dynamic, only between enclosures and conductor, not between phases
4. Protection against contamination and moisture
5. No losses in surrounding conductive material (grilles, railings, concrete reinforcements, lines, etc.)

The range of bus ducts are available up through 38 kV and includes continuous current ratings from about 5 up to 25 kA self-cooled, or 40 kA with forced cooling. The momentary current ratings have to match the rating of attached equipment. With high current ratings, more attention must be paid to the following:

1. Progressive rise of conductor temperature due to skin effects
2. Heating of surrounding conducting material by the magnetic field of conductors
3. High forces on main or component conductors in the event of a short circuit

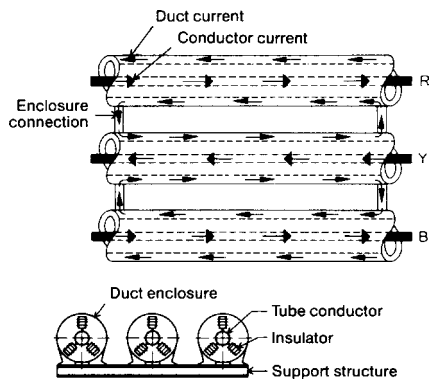


FIGURE 10-96 Three-phase arrangement of an isolated-phase bus duct and principle of enclosure connection; according to Kirchhoff's law sum of conductor currents (+) and sum of duct currents (−) is zero.

In an enclosure with sections of tube insulation (sectional enclosure), eddy currents exist with values as large as the conductor current. These give rise to heat losses, and so the magnetic field of the main conductor is not always compensated for sufficiently. An important technical feature of the bus duct, therefore, is the electrically continuous enclosure. The tubes enclosing each phase have electric conducting joints throughout their length and are short-circuited across the three phases at both ends. The enclosure thus constitutes a secondary circuit to the conductors (Fig. 10-96). The currents in the enclosures reach almost the corresponding conductor currents, depending on the resistance of the duct, but are of the opposite direction. The magnetic field outside the enclosure is almost completely eliminated, and thus there are no external losses or field forces between the phases. Connections to machines and switchgear must be adaptable and removable.

Current transformers for measurement and protection are of the bushing type or are integrated into the bus duct at a suitable place. Voltage transformers can be contained in the bus duct or mounted in separate instrument boards. The same applies to protective capacitors. Care must be taken that branch lines are adequately dimensioned with regard to thermal short-circuit strength.

The reliability of generator bus ducts can be enhanced by employing means to maintain the air pressure in the duct. Although, generally bus ducts are leakproof, the large number of dismantlable joints may cause a slight leakage and might lead to moisture condensation during a plant shutdown. Supplying the bus duct with filtered, precompressed air at slight pressure ensures that the air flow is

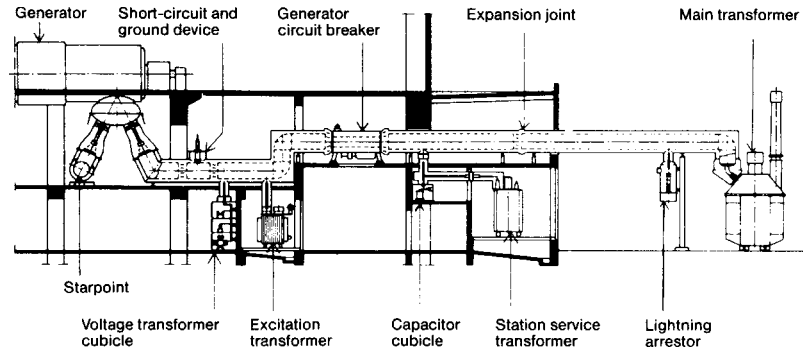


FIGURE 10-97 Generating-plant isolated-phase bus-duct arrangement with generator circuit breaker type DR.

only outward; contamination of the conductors is not possible. Drying the air by precompressing prevents condensation.

Short-circuiting and grounding facilities are required in the bus duct to protect the generator and also for maintenance grounding purposes. Manually positioned links and straps are sufficient for small unit ratings; motor-operated grounding switches are recommended for higher capacities. A typical isolated-phase bus arrangement of a power station including generator circuit breaker is shown in Fig.10-97.

10.3.5 Switchboards

Floor-mounted deadfront “switchboards” typically consist of an enclosure, molded case or low-voltage power circuit breakers, fusible or nonfusible switches, instruments, metering equipment, monitoring equipment and/or control equipment, and are fitted with associated interconnections and supporting structures. Switchboards can consist of one or more sections which are electrically and mechanically interconnected. Main disconnect devices can be mounted individually or be an integral part of a panel assembly. Definitions, ratings, design and production tests, construction requirements, and guidelines for application, handling, storage and installation are covered in NEMA PB-2⁵.

Switchboards are typically installed in industrial plants, utility and cogeneration facilities, and commercial and residential buildings for the distribution of electricity for light, heat, and power. They are typically available in voltage ratings of 600 V or less, continuous current ratings of 6000 A or less, and short-circuit current ratings up to 200 kA.

10.3.6 Arc-Resistant Metal-Enclosed Switchgear

The term “arc-resistant switchgear” indicates a design in which the equipment has met the requirements of ANSI/IEEE C37.20.7⁶. The switchgear assembly is subjected to an internal arcing fault in key locations throughout the assembly for a specified current level and duration and the equipment performance is evaluated against five basic criteria. The arcing fault is initiated by a small wire placed across the primary conductors which vaporizes when current flows, providing an ionized air path for the arc. The preferred current level for this test is the short-circuit rating of the equipment and the preferred duration for current flow is 0.5 s. The equipment is evaluated for its ability to mitigate conditions which could be hazardous to personnel working

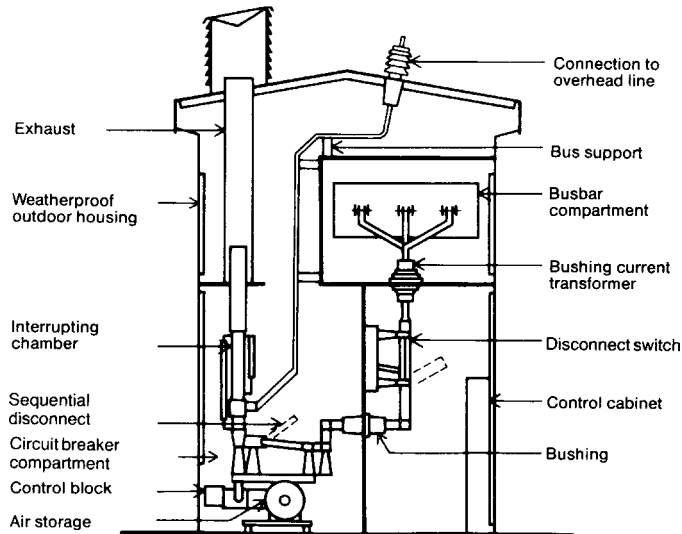


FIGURE 10-98 Metal-enclosed station-type switchgear cubicle for outdoor installation; equipped with a heavy-duty, air-blast circuit breaker, 14.4 kV, 3000 A, 50 kA.

nearby. Definitions, ratings, test requirements, and guidelines for application and installation are covered in IEEE C37.20.7⁶.

10.3.7 Station-Type Switchgear

Another type of switchgear assembly that was previously used is “*station-type switchgear*.” Station-type switchgear is no longer manufactured, but is briefly discussed here for historical purposes.

The term “station-type switchgear” indicates a design in which the major component parts of a circuit, such as buses, circuit breakers, disconnecting switches, and current and voltage transformers, are in separate metal housings, and the circuit breakers are of the stationary type (Fig. 10-98). Phase segregation in metal-enclosed switchgear is a type of design in which a 3-phase metal housing is divided into three single-phase compartments by means of single metal barriers.

Metal-enclosed station-type switchgear was used in industrial, commercial, and utility installations, generally for voltages of 14.4 to 69 kV, and continuous current ratings up to 5000 A.

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2. IEEE C37.20.2, *Standard for Metal-Clad Switchgear*.
3. IEEE C37.20.3, *Standards for Metal-Enclosed Interrupter Switchgear*.
4. IEEE C37.23, *Standard for Metal-Enclosed Bus*.
5. NEMA PB-2, *Standard for Deadfront Distribution Switchboards*.
6. IEEE C37.20.7, *Guide for Testing Metal-Enclosed Switchgear Rated up to 38 kV for Internal Arcing Faults*.

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- IEEE C37.21, *Standard for Control Switchboards.*
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10.4 VOLTAGE REGULATORS

BY CRAIG A. COLOPY

A primary objective of any electrical system is to provide power users with a supply voltage compatible with their utilization equipment. Every electrical device is designed to operate at a certain rated voltage for optimum efficiency and maximum length of service. An ideal electrical supply system provides constant voltage to all users under all loading conditions. No system is ideal; it is economically impractical to attempt an “ideal system” design approach. Today’s ideal system is that system providing a voltage supply satisfactory to all utilization equipment, with the most economical use of available regulation equipment.

Several methods of improving the voltage profile on electric transmission or distribution systems are in use. These include transformer load-tap changers, switched and fixed capacitors, and single and three-phase step-voltage regulators. Another new approach, static var control, employing thyristor phase-angle firing control of fixed capacitors is being applied experimentally on several high-voltage transmission systems. Application of single-phase, step-voltage regulators dominates the distribution market to a great extent. They are used in substations having up to 30 MVA loads, as well as being applied to distribution feeders and laterals.

An economical means of voltage regulation is desirable to provide power users with a voltage supply compatible with utilization equipment. The following list describes the effects of unregulated voltage:

1. Resistance loads (electric stoves, irons, water heaters, toasters, etc.)
 - a. Low voltage
 - (1) Longer heating time.
 - b. High voltage
 - (1) Shorter life of heating elements.
2. Motor loads (vacuum cleaners, washing machines, fans, refrigerators, etc.)
 - a. Low voltage
 - (1) Increased slip-increased line current under excited motor. Results: (a) decreased efficiency and (b) motor overheating.
 - b. High voltage
 - (1) Overexcited motor-increased torque. Result: possible damage to coupling or appliance.
3. Electronic loads (radio and television)
 - a. Low voltage
 - (1) Poorer quality of reception on television sets: (a) picture not distinct and (b) decreased picture size.
 - b. High voltage
 - (1) Shortens life of electronic components.
4. Illumination loads (incandescent and fluorescent lighting)
 - a. Low voltage
 - (1) Decreased incandescent lamp efficiency; a 10% decrease in voltage results in 70% normal illumination output.
 - (2) If voltage is too low, fluorescent lamps will be inoperative.
 - b. High voltage
 - (1) Life expectancy of bulbs decreases.

Of course, many benefits of regulated voltage provided to consumers also benefit suppliers by virtue of decreased investment per kVA distributed, increased efficiency of distribution equipment, and increased revenue. The intangible benefit of customer satisfaction must not be overlooked.

10.4.1 Methods of Regulation

The first regulators were induction-type machines. These appeared very early in the development of the electric power industry and were used extensively for a number of years. An induction regulator consists of a rotor and a stator much like a motor. Like step regulators, induction regulators take voltage from the source and add to or subtract from it to hold the load voltage steady. Output voltage is changed by mechanically adjusting the position of the rotor relative to the stator. The rotor does not rotate continuously but has its position changed as required by a small, internal self-contained motor. This motor responds to a signal from a control circuit.

Step-type voltage regulators, the precursors of modern design, were introduced in the early 1930s. The first step-type regulators were developed from the autobooster concept. A 2400-/120- V distribution transformer connected as an autotransformer gives a 5% boost. Adding a center tap to the secondary (series) winding gives two $2\frac{1}{2}\%$ steps. Adding two more taps give four $1\frac{1}{4}\%$ steps. A preventive

autotransformer (or bridging reactor) divides these steps in half to give the modern $\frac{5}{8}\%$ steps. In a $\pm 10\%$ regulator, thirty-two $\frac{5}{8}\%$ steps, 16 above and 16 below neutral, provide regulation to all types of loads. Step-type voltage regulators are actually tapped autotransformers. An autotransformer is a transformer in which part of one winding is common to both the primary and the secondary circuits associated with that winding. In other words, the primary (exciter) winding is both electrically and magnetically connected to the secondary (series) winding. The exciter winding is common to both primary and secondary; the series winding is connected in series with load (output) current. Step-type voltage regulators are commonly provided in both single-phase and three-phase styles.

Transformer load-tap changers (commonly referred to as LTC transformers) are actually combination transformers and step-type regulators. The tap-changing mechanism is mounted in an oil-filled compartment which is commonly sealed from the core and coil. Tap changing is accomplished by a gang-operated, three-phase oil switch providing simultaneous regulation of the three-phase voltages.

Fixed and switched capacitors are not voltage regulators in the electrical definition of the device. Capacitors are used to improve the line-voltage profile by connecting a "bank" of capacitors in shunt. These shunt capacitors first improve an otherwise lagging power factor "seen" by a source. The effect of the improved power factor will be reduced line losses and improved regulation. The use of capacitors beyond that required to attain unity power factor will result in a leading component of current in the line inductance, causing voltage on the line to rise. As long as total line current remains lagging, capacitors provide an improved voltage profile. When total current is leading, however, shunt capacitors increase line current (and line losses) and may cause a large voltage rise, resulting in excessively high voltage.

Static var systems (SVS) involve effectively regulating (or fine tuning) the reactive compensation afforded by the shunt capacitors by virtue of phase-angle firing control of thyristors. Basically, the thyristor conduction period will establish the capacitive (leading) current. The control system used is very rapid relative to system fluctuations, permitting optimization of the application. Other features of SVS, especially its use in improving system stability, have made it feasible for exploration on transmission systems. Thus far, SVS application at distribution voltages has been justified only for very large bulk power supplies.

Method of Step-Voltage-Regulator Operation. A typical step-voltage regulator (Fig. 10-99) involves a shunt winding, a series winding, and a bridging reactor or preventive autotransformer.

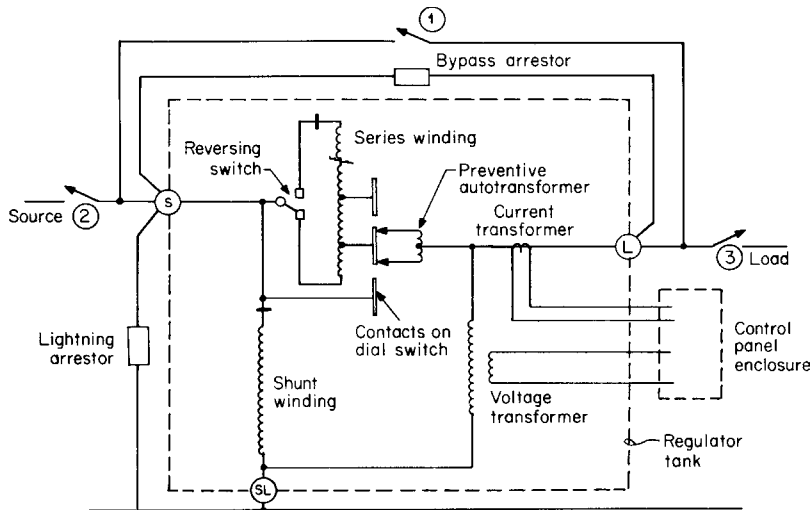


FIGURE 10-99 Wiring diagram of a typical distribution step-voltage regulator showing both external and internal connections, with preventive autotransformer shown on a nonbridging position: (1) bypass switch; (2) source switch; (3) load switch.

Taps, each representing essentially $1\frac{1}{4}\%$ voltage, are affixed to the series winding and brought to a specially designed dial switch.

The *main transformer* comprises the *shunt winding* and the *series winding* (Fig. 10-100a). The series winding most often is rated at 10% voltage of the shunt winding. Usually eight taps on the series winding are brought to a *dial-switch* assembly as individual contacts, with the voltage difference between contacts being $1\frac{1}{4}\%$ voltage.

The terminals of a center-tapped *preventive autotransformer* are able to transit (slide) between the dial switch contacts in a manner which avoids momentary loss of load. As one finger advances to the next step, arcing results because of the inductive nature of the reactor, but load current is maintained (Fig. 10-100b) through the finger which does not part contact. When the parting finger remakes on the adjacent contact, a bridging condition is established (Fig. 10-100c). A circulating current is established through the preventive autotransformer (PA), or a center tapped bridging reactor, and load voltage is seen to be the average voltage of the taps being bridged. To minimize the arc duration, a *quick-break mechanism* accelerates the moving contacts. The rapid separation of the contacts and the use of contact tips composed of a tungsten-carbon alloy mitigate the attendant ablation of contact material.

A *reversing switch* permits the polarity of the series winding to be reversed relative to the shunt winding, thereby accommodating plus and minus regulation with the same series winding.

A *voltage transformer* and *current transformer* are used to provide voltage and current supplies, respectively necessary for the control to perform its function.

Dielectric protection of the series winding is afforded by the *bypass arrestor*. A surge propagated on the line will be shunted past the regulator. *Lightning arrestors*, often provided at both the source and the load terminals, similarly protect the regulator from overvoltage surge conditions.

Other external appurtenances will include the three bushings (source, load, and SL or common), a *tap position indicator* display of the present operating position of the regulator, and a *control panel enclosure*.

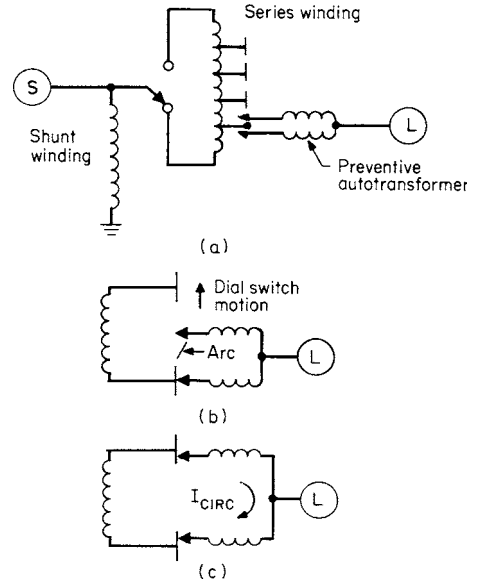


FIGURE 10-100 Operations of the internal mechanisms of the regulator.

Regulator Control Circuitry. This technology has progressed from a mechanically driven regulating relay beam to highly sophisticated, microprocessor-based digital control circuitry. All regulator controls comprise three major parts:

1. A *voltage-sensing device* which monitors the output voltage of the regulator and sends a signal to the motor drive circuitry
2. An *amplifying or switching section*, with or without time delay, which delays and/or transmits the signal
3. A *motor drive circuit* which responds to the signal by closing relay contacts or actuating electronic switches that cause the tap-changing motor to operate the tap changer correct the voltage

The important functions of the typical regulator control are shown in the block diagram in Fig. 10-101.

An *auxiliary voltage source*, such as a nominal 120-V tertiary winding on the main coil and/or a separate voltage transformer, will be provided to supply power to the tap changer motor and the base voltage for deriving the regulator output voltage. This 120 V is scaled down in a *sensing trans-*

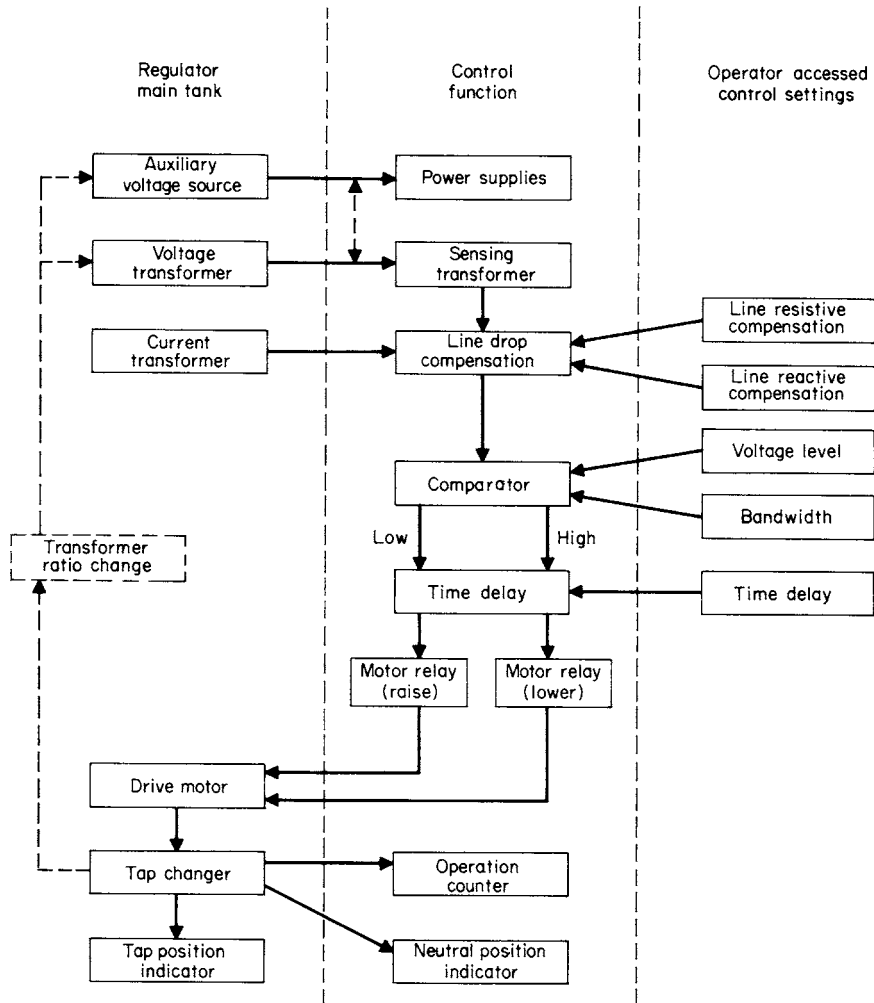


FIGURE 10-101 Regulator control functions.

former which may itself be tapped to facilitate ratio adjustment if the voltage source is not exactly as required. The output of the sensing transformer will, by operator selection, be altered to reflect the voltage drop between the regulator and the load. This drop, which is a function of the load current and the line impedance, is modeled by knowing the current from a *current transformer* and established *line resistive compensation* and *line reactive compensation* parameters.

The voltage, now compensated for line drop, is related in a *comparator* to the desired voltage level as established by a *voltage-level* setting and a *bandwidth* or tolerable voltage range limits setting.

If the compensated voltage exceeds the high limit (or is less than the low limit), a *time delay* is activated. Requiring the voltage to remain out-of-band for a period of typically 30 to 60 s assures that the voltage-level change is of sufficient duration to warrant regulator action.

After the preset delay is satisfied, a *drive motor* is powered and runs the *tap changer* to the next position. Tap-changer motion advances the *operation counter*, moves the *tap position indicator* pointer, and causes illumination of a special *neutral position indicator* light, if in neutral position.

Of course, the new tap position in turn causes a *transformer ratio change*, altering the input to the sensing transformer and closing the control function loop.

10.4.2 Application of Regulators

The rating of single-phase step-voltage regulators is a simple function of the rated range of regulation and the current. For example, a 100-A regulator with a $\pm 10\%$ range of regulation for a 7620-V system will be rated

$$100 \text{ A} \times 0.10 \times 7620 \text{ V} = 76.2 \text{ kVA}$$

Early recognition that this is 10% of circuit kVA will avoid later difficulties.

The ampere rating of regulators can be increased by limiting the range of regulation to accommodate higher line currents. By limiting the range of regulation, the portion of series winding through which line current passes is decreased. This decrease in the portion of series winding “seeing” load current decreases the internal regulator losses. By decreasing losses, heating inside the regulator is decreased. Consequently, the regulator may carry more load current for the same temperature rise. For example, a 100-A regulator, $\pm 10\%$, may be operated at $\pm 5\%$ regulation at 160 A. Limit-switched taps and overload capabilities are, by ANSI standards, $8\frac{3}{4}\%$ (110%), $7\frac{1}{2}\%$ (120%), $6\frac{1}{4}\%$ (135%), 5% (160%), to a limit of 668 A.

Oil-immersed step-type regulators, by ANSI standards, are rated at 55°C average winding temperature rise. A 65°C hot-spot winding temperature is also specified in regulator standards. The short-circuit withstand capacity of standard regulators is 25 times normal full-load current for 2 s.

Using single-phase regulators in three-phase installations is a very common application. Configuring the regulators in wye, closed delta, and open delta are acceptable alternatives, depending on system conditions.

The wye connection is invariably used on grounded-neutral 4-wire systems. Regulator sizing is a straightforward adaptation of single-phase principles.

The use of three single-phase regulators in closed delta requires that recognition be made of how current will flow in the regulator. Especially important is the fact that system line current and regulator series winding current are not the same. The application will be specified based on load current, but the current in the regulator series winding will establish the regulator size required. Also, the closed-delta application results in a $\pm 15\%$ range of regulation in the line voltage for a $\pm 10\%$ range section on the individual single-phase regulators. Another point which is significant when modeling for line-drop compensation or sensing a power reversal is to note that the current and voltage signals from the regulators will be displaced by 30° (lead or lag) at unity power factor of the load.

An open-delta connection is sometimes used to save expense. This system is like a wye connection in that line current and series winding current are identical, but like a delta in that the 30° phase shift occurs; in fact, in this case the shift is leading in one regulator and lagging in the other.

The various regulator connections utilize the installed kVA of regulators with differing efficiency. For each 1000 kVA of system capacity, the use of $\pm 10\%$ regulators will require total regulator capacity of as given in the following table:

Grounded wye	100 kVA
Closed delta	123 kVA
Open delta	115 kVA

Another important consideration when applying single-phase regulators in three-phase installations is that certain single-phase regulator connections may be unsafe. In deciding on the proper and safe connection for a given application, three basic phenomena should be considered (1) third harmonics, (2) system line surges, and (3) line faults.

For instance, when single-phase regulators are grounded on an ungrounded system, a resonant circuit is possible between the third-harmonic magnetizing reactance of the regulators and line

capacitance. This resonance can intensify third-harmonic voltages to unsafe levels. A similar situation can occur when regulators are ungrounded on either a grounded or an ungrounded system. To protect from line surges, regulator connection is unimportant as long as a bypass arrester and line-to-ground arresters are used. Line-to-ground fault problems may be serious when regulators are ungrounded on a grounded system or grounded on an ungrounded system. A problem may also occur when regulators are connected in either open- or closed-delta configuration on a grounded system. Table 10-11 summarizes safe and unsafe single-phase regulator connections. A feature of regulators is that they may be bypassed in service such that load interruption is not necessary during installation procedures. It is critical that proper switching procedures be followed to avoid the extremely high circulating current which will appear in the series winding if bypassing occurs at other than the neutral tap position. When placing a regulator on the line (see Fig. 10-101), three switches are commonly used: a source switch, load switch, and bypass switch. To place the regulator in service, first the source switch is closed. The regulator is checked out by running the tap changer in the raise and lower directions. The regulator is returned to the neutral position, and the load switch is closed. Caution must be taken to make sure that the regulator will not make an automatic tap change when the load switch is closed. After the load switch is closed, the bypass switch may be opened. To take the regulator out of service, the procedure is reversed. First the regulator is run to the neutral position, the bypass switch is closed, the load switch is opened, and then finally the source switch is opened. Once again, caution must be taken to prevent the regulator from making an automatic tap change during this switching procedure by assuring isolation of the control power.

Regulators may be paralleled if and only if sufficient loop impedance exists to limit circulating currents, based on the maximum difference in the voltages of the two circuits V_1 and V_2 . Equally important, the percent impedances of the two circuits must be equal or very close. The common practice is that the two impedances must be close enough so that circulating current does not exceed 10% of rated current when operating on equal voltage taps. For impedance Z_1 of circuit 1 and Z_2 of circuit 2, percent circulating current is given approximately by

$$\% \text{ circulating current} = \frac{Z_1 - Z_2}{Z_1 + Z_2} \times 100$$

When regulators are paralleled, it is necessary that the tap-changing mechanisms be on as nearly the same tap position as possible. If they are not, a circulating current of magnitude $I_c = (V_1 - V_2)/(Z_1 + Z_2)$ will flow in the loop. The most widely used method for paralleling regulators is the “current-balance” method. Circulating current is separated from load current by means of auxiliary current transformers. This current is fed into the voltage reference circuit to cause the unit to change taps to reduce the circulating current.

Regulators are often applied in series, or cascaded, on the same feeder. In this application, two or more regulators operate to control the voltage profile along with a distribution line. The most important

TABLE 10-11 Safe and Unsafe Regulator Connections

Regulator connection	System connection	Effect			Conclusion
		Third harmonic	Line surges	Line ground	
Grounded Y	Grounded	S	S_1	S	S
Ungrounded Y	Ungrounded	U	S_1	U	U
Delta	Grounded	S	S_1	S_2	S_2
Open delta	Grounded	S	S_1	S_2	S_2
Grounded Y	Ungrounded	U	S_1	U	U
Ungrounded Y	Ungrounded	U	S_1	S	U
Delta	Ungrounded	S	S_1	S	S
Open delta	Ungrounded	S	S_1	S	S

Key: S = Safe; S_1 = safe if suitable bypass series winding protection is supplied; S_2 = conditionally safe—overexcitation of regulators may lead to their failure if fault allowed to persist; U = unsafe.

consideration in such applications is the time-delay settings on the regulator controls. The modern solid-state control is adjustable from at least 15 to 105 s. When regulators are cascaded, the first regulator (at or closest to the substation) should be set with the shortest time delay, with progressively longer delays farther away from the station. If the settings are reversed, the farthest regulator would attempt to correct all voltage fluctuations first. As the load change appeared at the other regulators on the line, each would attempt to compensate for it in order. When finally the substation unit reacted, it would raise the overall voltage level, making it necessary for each successive unit down the line to back down accordingly.

Setting of the regulator control must be accomplished with care to assure proper regulator operation and proper supply voltage for the users.

The voltage-level setting is the voltage which the regulator is to maintain at its output, expressed on a 120-V base. (Note that this will be the voltage at the “load center” if line-drop compensation is used, as explained later.)

To avoid a hunting condition of the regulator, a *bandwidth* is set to define the limits of acceptable voltage about the voltage-level setting. The stated bandwidth is the total range, such that a regulator set for 120 V with a 2-V bandwidth will be “in-band” if the output is in the range of 119 to 121 V. The bandwidth setting must be larger than the voltage change expected from a single tap change or a hunting situation will occur. Beyond this, it is a qualitative judgment; a lower setting will maintain a closer output voltage tolerance, a higher setting will reduce tap-changer operations, extending the regulator life.

The *time delay* is the time duration outside of the prescribed band required before tap-changer actuation. As noted earlier, this is very important in cascaded operations. Otherwise, it will be set at typically 30 to 60 s to avoid unduly quick responses to line-voltage fluctuations.

The use of *line-drop compensation* will cause the regulator to hold the voltage-level setting at a point remote from the regulator, rather than at the regulator location. The classic illustration of the application of line-drop compensation involves a “load center” some miles from the substation. It is required to hold a given voltage at the load. Given that the line is inductive in nature, this implies holding a higher voltage at the substation, the incremental voltage increase being a function of the line impedance (resistive and reactive) and the line current. Thus, the two line-drop compensation settings are the resistive and reactive models of the line, calibrated in a 0- to 24-V basis, reflecting the drop to be anticipated (on a 120-V base) between the regulator and the load when the system is carrying rated regulator current.

Tables are provided with the regulators to use in determining the proper settings. A simplified example demonstrates the procedure:

1. The wye-connected regulators are rated 76.2 kVA, 7620 V (= 100 A).
2. The load center is 4 mi from the regulators.
3. The feeder to the load center is 2/0 ACSR on 36 in center spacing.

The solution to this example is as follows:

1. Tables provided with the regulator will show

- a. Line resistance $\approx 0.90 \Omega/\text{mi}$
- b. Line reactance $\approx 0.77 \Omega/\text{mi}$

2. Calculate compensation as

- a.
$$\frac{\text{CT primary rating}}{\text{Voltage transformer ratio}} \times R/\text{mi} \times \text{miles} = R \text{ comp set}$$
- b.
$$\frac{\text{CT primary rating}}{\text{Voltage transformer ratio}} \times X/\text{mi} \times \text{miles} = X \text{ comp set}$$

$$R_{\text{comp set}} = 5.7 \text{ or } 6 \text{ V}$$

$$X_{\text{comp set}} = 4.9 \text{ or } 5 \text{ V}$$

Thus the required 120 V will be held at the load. Changes in load current are automatically compensated.

Each line-drop compensation application needs individual consideration. Conditions which would invalidate this example are single-phase or delta connection or the regulators. Also, the example of a precise load center is seldom encountered in practice. For this reason, the setting of line-drop compensation must often be tempered with knowledge of actual system conditions.

Several control accessories are available to provide more sophisticated feeder loading control. These devices have served to make modern feeder regulators the “nerve center” of the distribution system. A *voltage-limit control* device provides automatic limit of regulator output voltage. Settings for both upper and lower limits protect against extremely heavy, light, or unusual loading conditions. A review of the use of line-drop compensation may show that at the highest anticipated loading, the voltage at the regulator is too high for proper customer utilization. Then an upper-limit voltage-limit control may be required to protect a load close to the regulator by overriding the line-drop compensation function. A *reverse power flow detector* can monitor source-side voltage with an internal source-side voltage supply, detect a reversal of power flow direction, and “turn the regulator around” electrically so that it regulates in the proper direction. A *voltage-reduction control*, which can be operated locally or from a remote control, provides automatic voltage reduction in preselected percentages. This is particularly useful where system capacity is close to peak load; studies have shown that a 5% voltage reduction can reduce system load by almost 5%.

10.4.3 Regulator Developments

Innovation associated with step-voltage regulators has concentrated in recent years on the electronic control. The very nature of digital controls now offered routinely with new step-voltage regulators facilitates the mathematical manipulation of the measured line voltage and current into additional system parameters of interest to the user. Thus, controls are available which will display voltage, current, power factor, kW, kvar, various time-integrated demand quantities, and other conditions of interest.

An additional feature available on many controls is the ability to serially communicate this information to a remote-terminal unit (RTU) so that the regulator control becomes the sensory apparatus of the supervisory control and data acquisition (SCADA) system, eliminating the need for multiple transducers and the attendant analog signals.

10.5 POWER CAPACITORS

By JEFFREY H. NELSON and ROBERT L. KLEEB

Definitions of terms used in this section can be found in the IEEE standards and application guides referenced in this section and/or in the *IEEE Authoritative Dictionary of Terms*.

10.5.1 System Benefits of Power Capacitors

Power capacitors provide several benefits to power systems. Among these include power factor correction, system voltage support, increased system capacity, reduction of power system losses, reactive power support, and power oscillation damping.

Power Factor Correction. In general, the efficiency of power generation, transmission, and distribution equipment is improved when it is operated near unity power factor. The least expensive way to achieve near unity power factor is with the application of capacitors. Capacitors provide a static source of leading reactive current and can be installed close to the load. Thus, the maximum efficiency may be realized by reducing the magnetizing (lagging) current requirements throughout the system. Table 10-1 is a simple tool that can be used to determine the kilovars (kvar) required for

correcting the system power factor. From Table 10-12, find the row that corresponds to the existing power factor and the column that corresponds to the desired power factor and select the kilowatt multiplier where these intersect. Then simply multiply this factor by the power system load in kilowatts to determine the kilovars required to be installed to achieve the desired power factor.

For example, with a load of 200 kW at 77% power factor, how many capacitor kilovars are needed to correct to a power factor of 95%? At the point where the row for the 77% existing power factor and the column for the desired power factor of 95% intersect, we find a kilowatt multiplier of 0.5. Therefore, the following calculation can be made to determine the kvar required to achieve 95% power factor.

$$\begin{aligned}\text{Example} \quad 3\phi \text{ kvar} &= 3\phi \text{ load (kW)} \times \text{kilowatt multiplier} \\ &= 200 \text{ kW} \times 0.5 \\ &= 100 \text{ kvar}\end{aligned}\tag{10-76}$$

System Voltage Support. Power systems are predominately inductive in nature and during peak load conditions or during system contingencies there can be a significant voltage drop between the voltage source and the load. Application of capacitors to a power system results in a voltage increase back to the voltage source, and also past the application point of the capacitors in a radial system. The actual percentage increase of the system voltage is dependent upon the inductive reactance of the system at the point of application of the capacitors. The short-circuit impedance at that point is approximately the same as the inductive reactance; therefore, the 3-phase short-circuit current at that location can be used to determine the approximate voltage rise. The following rule-of-thumb equation is commonly used

$$\Delta V \approx \frac{\text{kvar}_C}{\text{kVA}_{SC}} \times 100\% \tag{10-77}$$

where ΔV = percent voltage rise at the point of the capacitor installation, kvar_C = capacitor 3-phase kvar, kVA_{SC} = system 3-phase short-circuit kVA at the point of the capacitor installation.

$$\text{kVA}_{SC} = \sqrt{3} \times V_{LL} \times I_{SC} \tag{10-78}$$

where V_{LL} = system line-to-line (phase-to-phase) voltage, I_{SC} = is the 3-phase short-circuit current at the point of the capacitor installation.

Increased System Capacity. The application of shunt or series capacitors can affect the power system capacity.

Application of shunt capacitors reduces the inductive reactive current on the power system, and thus reduces the system kVA loading. This can have the effect of increasing system to serve additional load.

Series capacitors are typically used to increase the power carrying capability of transmission lines. Series capacitors insert a voltage in series with the transmission line that is opposite in polarity to the voltage drop across the line, which decreases the apparent reactance and increases the power transfer capability of the line.

Power System Loss Reduction. The installation of capacitors can reduce the current flow in a power system. Since losses are proportional to the square of the current, a reduction in current will lead to reduced system losses.

Reactive Power Support. Capacitors can help support steady-state stability limits and reactive power requirements at generators.

Power Oscillation Damping. Controlled series capacitors can provide an active damping for power oscillations that many large power systems experience. They can also provide support after significant disturbances to the power system and allow the system to remain in synchronous operation.

TABLE 10-12 Power Factor Correction Kilowatt Multiples

Present power factor percentage	Corrected power-factor percentage																				
	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	98	99	100
50	0.982	1.008	1.034	1.060	1.086	1.112	1.139	1.165	1.192	1.220	1.248	1.276	1.306	1.337	1.369	1.403	1.442	1.481	1.529	1.590	1.732
51	0.937	0.962	0.989	1.015	1.041	1.067	1.094	1.120	1.147	1.175	1.203	1.231	1.261	1.292	1.324	1.358	1.395	1.436	1.484	1.544	1.687
52	0.893	0.919	0.945	0.971	0.997	1.023	1.050	1.076	1.103	1.131	1.159	1.187	1.217	1.248	1.280	1.314	1.351	1.392	1.440	1.500	1.643
53	0.850	0.876	0.902	0.928	0.954	0.980	1.007	1.033	1.060	1.088	1.116	1.144	1.174	1.205	1.237	1.271	1.308	1.349	1.397	1.457	1.600
54	0.809	0.835	0.861	0.887	0.913	0.939	0.966	0.992	1.019	1.047	1.075	1.103	1.133	1.164	1.196	1.230	1.267	1.308	1.356	1.416	1.559
55	0.769	0.795	0.821	0.847	0.873	0.899	0.926	0.952	0.979	1.007	1.035	1.063	1.090	1.124	1.156	1.190	1.228	1.268	1.316	1.377	1.519
56	0.730	0.756	0.782	0.808	0.835	0.860	0.887	0.913	0.940	0.968	0.996	1.024	1.051	1.085	1.117	1.151	1.189	1.229	1.277	1.338	1.480
57	0.692	0.718	0.744	0.770	0.796	0.822	0.849	0.875	0.902	0.930	0.958	0.986	1.013	1.047	1.079	1.113	1.151	1.191	1.239	1.300	1.442
58	0.655	0.681	0.707	0.733	0.759	0.785	0.812	0.838	0.865	0.893	0.921	0.949	0.976	1.010	1.042	1.076	1.114	1.154	1.202	1.263	1.405
59	0.618	0.644	0.670	0.696	0.722	0.748	0.775	0.801	0.828	0.856	0.884	0.912	0.939	0.973	1.005	1.039	1.077	1.117	1.165	1.226	1.368
60	0.584	0.610	0.636	0.662	0.688	0.714	0.741	0.767	0.794	0.822	0.850	0.878	0.905	0.939	0.971	1.005	1.043	1.083	1.131	1.192	1.334
61	0.549	0.575	0.601	0.627	0.653	0.679	0.706	0.732	0.759	0.787	0.815	0.843	0.870	0.904	0.936	0.970	1.008	1.048	1.096	1.157	1.299
62	0.515	0.541	0.567	0.593	0.619	0.645	0.672	0.698	0.725	0.753	0.781	0.809	0.836	0.870	0.902	0.936	0.974	1.014	1.062	1.123	1.265
63	0.483	0.509	0.535	0.561	0.587	0.613	0.640	0.666	0.693	0.721	0.749	0.777	0.804	0.838	0.870	0.904	0.942	0.982	1.030	1.091	1.233
64	0.450	0.476	0.502	0.528	0.554	0.580	0.607	0.633	0.660	0.688	0.716	0.744	0.771	0.805	0.837	0.871	0.909	0.949	0.997	1.058	1.200
65	0.419	0.445	0.471	0.497	0.523	0.549	0.576	0.602	0.629	0.657	0.685	0.713	0.740	0.774	0.806	0.840	0.878	0.918	0.966	1.027	1.169
66	0.388	0.414	0.440	0.466	0.492	0.518	0.545	0.571	0.598	0.626	0.654	0.682	0.709	0.743	0.775	0.809	0.847	0.887	0.935	0.996	1.138
67	0.358	0.384	0.410	0.436	0.462	0.488	0.515	0.541	0.568	0.596	0.624	0.652	0.679	0.713	0.745	0.779	0.817	0.857	0.905	0.966	1.108
68	0.329	0.355	0.381	0.407	0.433	0.459	0.486	0.512	0.539	0.567	0.595	0.623	0.650	0.684	0.716	0.750	0.788	0.828	0.876	0.937	1.079
69	0.299	0.325	0.351	0.377	0.403	0.429	0.456	0.482	0.509	0.537	0.565	0.593	0.620	0.654	0.686	0.720	0.758	0.798	0.840	0.907	1.049
70	0.270	0.296	0.322	0.348	0.374	0.400	0.427	0.453	0.480	0.508	0.536	0.564	0.591	0.625	0.657	0.691	0.729	0.769	0.811	0.878	1.020
71	0.242	0.268	0.294	0.320	0.346	0.372	0.399	0.425	0.452	0.480	0.508	0.536	0.563	0.597	0.629	0.663	0.701	0.741	0.783	0.850	0.992
72	0.213	0.239	0.265	0.291	0.317	0.343	0.370	0.396	0.423	0.451	0.479	0.507	0.534	0.568	0.600	0.634	0.672	0.712	0.754	0.821	0.963
73	0.186	0.212	0.238	0.264	0.290	0.316	0.343	0.369	0.396	0.424	0.452	0.480	0.507	0.541	0.573	0.607	0.645	0.685	0.727	0.794	0.936
74	0.159	0.185	0.211	0.237	0.263	0.289	0.316	0.342	0.369	0.397	0.425	0.453	0.480	0.514	0.546	0.580	0.618	0.658	0.700	0.767	0.909
75	0.132	0.158	0.184	0.210	0.236	0.262	0.289	0.315	0.342	0.370	0.398	0.426	0.453	0.487	0.519	0.553	0.591	0.631	0.673	0.740	0.882
76	0.105	0.131	0.157	0.183	0.209	0.235	0.262	0.288	0.315	0.343	0.371	0.399	0.426	0.460	0.492	0.526	0.564	0.604	0.652	0.713	0.885
77	0.079	0.105	0.131	0.157	0.183	0.209	0.236	0.262	0.289	0.317	0.345	0.373	0.400	0.434	0.466	0.500	0.538	0.578	0.620	0.687	0.829
78	0.053	0.079	0.105	0.131	0.157	0.182	0.210	0.236	0.263	0.291	0.319	0.347	0.374	0.408	0.440	0.474	0.512	0.552	0.594	0.661	0.803
79	0.026	0.052	0.078	0.104	0.130	0.156	0.183	0.209	0.236	0.264	0.292	0.320	0.347	0.381	0.413	0.447	0.485	0.525	0.567	0.634	0.776

80	0.000	0.026	0.052	0.078	0.104	0.130	0.157	0.183	0.210	0.238	0.266	0.294	0.321	0.355	0.387	0.421	0.459	0.499	0.541	0.608	0.750
81		0.000	0.026	0.052	0.078	0.104	0.131	0.157	0.184	0.212	0.240	0.268	0.295	0.329	0.361	0.395	0.433	0.473	0.515	0.582	0.724
82			0.000	0.026	0.052	0.078	0.105	0.131	0.158	0.186	0.214	0.242	0.269	0.303	0.335	0.369	0.407	0.447	0.489	0.556	0.698
83				0.000	0.026	0.052	0.079	0.105	0.132	0.160	0.188	0.216	0.243	0.277	0.309	0.343	0.381	0.421	0.463	0.530	0.672
84					0.000	0.026	0.053	0.079	0.106	0.134	0.162	0.190	0.217	0.251	0.283	0.317	0.355	0.395	0.437	0.504	0.645
85						0.000	0.027	0.053	0.080	0.108	0.136	0.164	0.191	0.225	0.257	0.291	0.329	0.369	0.417	0.478	0.620
86								0.026	0.053	0.081	0.109	0.137	0.167	0.198	0.230	0.265	0.301	0.343	0.390	0.451	0.593
87									0.027	0.055	0.082	0.111	0.141	0.172	0.204	0.238	0.275	0.317	0.364	0.425	0.567
88										0.028	0.056	0.084	0.114	0.145	0.177	0.211	0.248	0.290	0.337	0.398	0.540
89											0.028	0.056	0.086	0.117	0.149	0.183	0.220	0.262	0.309	0.370	0.512
90												0.028	0.058	0.089	0.121	0.155	0.192	0.234	0.281	0.342	0.484
91													0.030	0.061	0.093	0.127	0.164	0.206	0.253	0.314	0.456
92														0.031	0.063	0.097	0.134	0.176	0.223	0.284	0.426
93															0.032	0.066	0.103	0.145	0.192	0.253	0.395
94																0.034	0.071	0.113	0.160	0.221	0.363
95																	0.037	0.079	0.126	0.187	0.328
96																		0.042	0.089	0.150	0.292
97																			0.047	0.108	0.251
98																				0.061	0.203
99																					0.142

10.5.2 Capacitor Units

The terms capacitor unit, power capacitor or capacitor may be used interchangeably.

The base standard which covers the ratings and requirements for capacitor units is IEEE 18¹. This standard applies to capacitors rated 216 V or higher, 2.5 kvar or more, and designed for shunt connection on alternating current (ac) power systems operating at a nominal power frequency of 50 or 60 Hz. IEEE 18 covers service conditions, ratings and capabilities, manufacturing, and testing of shunt capacitor units.

IEEE 824² specifies ratings, capabilities and testing requirements in addition to IEEE 18¹ for capacitor units to be utilized in series capacitor banks.

IEEE 1531³ covers considerations to take into account when specifying units to be used in a harmonic filter bank.

There are typically two voltage classes of capacitor units applied and they are divided into the categories of low-voltage capacitors (below 1000 V) and high-voltage capacitors (1000 V and above).

Low-Voltage Capacitor Units. Low-voltage capacitor units are typically applied in industrial power systems. They are generally available in voltage ratings from 240 to 600 V over the range of 2.5 to 100 kvar 3-phase. Low-voltage capacitors are typically dry type, metalized polypropylene film (see Fig. 10-102). Typical voltage and kvar ratings are listed in IEEE 18¹.



FIGURE 10-102 Typical low-voltage capacitor unit with self-healing metalized polypropylene capacitor elements, liquid-free enclosure and 3-phase connection terminals.

High-Voltage Capacitor Units. High-voltage capacitor units are typically connected to industrial power systems or to utility transmission and distribution power systems. The units are generally available in voltage ratings from 2.4 to 25 kV. Modern manufacturing techniques continue to decrease the size of high-voltage capacitor units which continues to increase the available kvar ratings for units. Typical voltage and kvar ratings are listed in IEEE 18¹.

The capacitor elements in present day high-voltage capacitor units are manufactured using an *all-film dielectric*, typically two layers of polypropylene film between two layers of thin aluminum foil. The capacitor elements are connected in a series/parallel combination to achieve the desired voltage and kvar rating. The elements are placed in a metal enclosure with bushings for external connections and impregnated with a dielectric fluid, usually under vacuum. The unit is then hermetically sealed (see Fig. 10-103).

Capacitor Unit Ratings. IEEE 18¹ establishes the following standard ratings for capacitor units, as applied under the normal service conditions and ambient temperatures defined in the standard:

1. Voltage, rms (terminal-to-terminal)
2. Terminal to case (or ground) insulation class
3. Reactive power
4. Number of phases
5. Frequency

Capacitors are intended to be operated at or below their rated voltage. They are designed to operate at overvoltages of 10% for bank contingencies, such as the failure of an individual unit or element, or system contingencies, such as a high voltage. Note that the overvoltage capability of the individual capacitor elements inside the unit is 110% of its portion of the unit voltage rating. The capacitor unit is capable of operating continuously under contingency conditions provided that the peak voltage

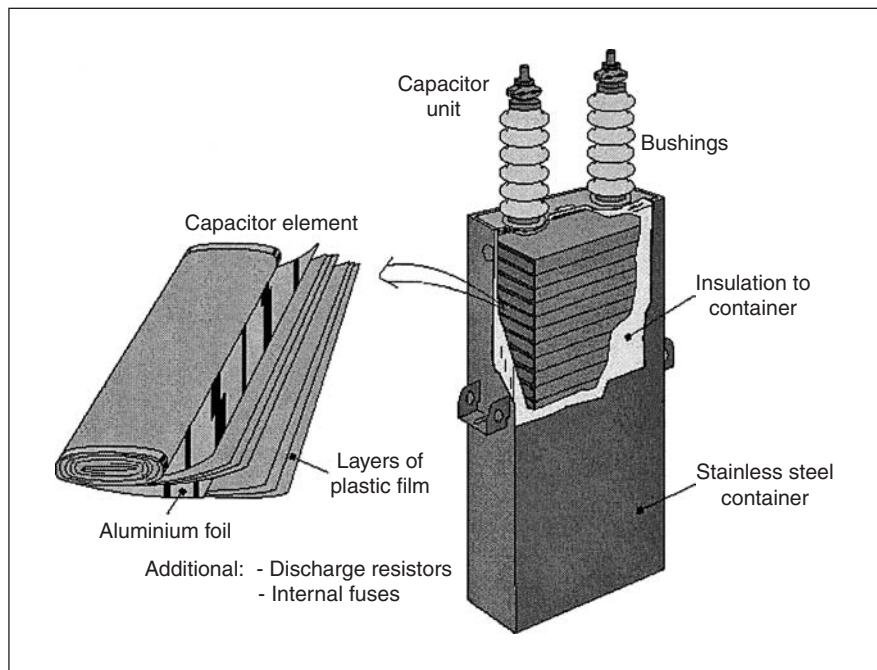


FIGURE 10-103 Typical high-voltage capacitor unit.

does not exceed 120% of rated peak voltage, including harmonics. The maximum peak voltage rating of the capacitor including harmonics, but excluding transients, is equal to

$$V_{pk} = 1.2\sqrt{2}(V_{rms} \text{ rated}) \quad (10-79)$$

Also, the unit is designed to operate continuously if the current does not exceed 135% of nominal rms current based on rated kvar and rated voltage, and the kvar output does not exceed 135% of rated kvar. The total rms current is equal to

$$I_{rms} = \sqrt{(I_1)^2 + (I_2)^2 + (I_3)^2 + \cdots + (I_n)^2} \quad (10-80)$$

where n = harmonic number.

The kvar output of the capacitor increases as the square of the applied voltage

$$\text{kvar}_{E_2} = \text{kvar}_{E_1} \frac{(E_2)^2}{(E_1)^2} \quad (10-81)$$

For example, a 200-kvar, 7200-V capacitor unit will supply 242 kvar at 7920 V

$$\begin{aligned} \text{kvar}_{E_2} &= 200 \frac{(7920)^2}{(7200)^2} \\ \text{kvar}_{E_2} &= 242 \text{ kvar} \end{aligned}$$

Transient Overvoltage and Overcurrent Withstand Capabilities. When the installation of a switched rack or bank is contemplated, other nearby capacitor equipment must be evaluated.

Capacitor banks switched in a back-to-back configuration can create very high peak magnitude and high frequency current transients.

Also, when switching a capacitor bank without any type of transient suppression a voltage transient is generated, typically in the range of 300 to 800 Hz. This undamped voltage transient can couple through a power transformer to a lower voltage system and be transmitted several miles away. If a capacitor bank is installed on the lower voltage system, a resonant condition may exist. If the resonant frequency of the LC circuit on the high-voltage bus where the capacitor bank is being switched is approximately equal to the LC circuit at the lower voltage capacitor bank, the voltage transient will be magnified. This phenomenon is known as voltage magnification.

These switching conditions could result in high overvoltage and overcurrent transients. The use of series reactors, preinsertion inductors or resistors, and/or special switching devices is sometimes required to reduce these transients to safe levels.

Transient overvoltage and overcurrent capabilities for shunt capacitors are covered in IEEE 1036⁴. Prior to 2002, they were covered in IEEE 18¹.

Capacitance Tolerance. In the 2002 revision to IEEE 18, the allowable capacitance tolerance for shunt capacitor units was changed to 0% from +10% of the nominal value based on rated kvar, voltage and frequency, measured at 25°C uniform case and internal temperature. In previous versions of IEEE 18, the allowable capacitance tolerance was 0% to +15%. However, with today's modern manufacturing practices, capacitance tolerances typically do not exceed +5% for standard units.

A tighter tolerance may be specified for units to be utilized in a harmonic filter capacitor bank, for example, -2% to +2% of the nominal capacitance. This tolerance may be applied to the capacitance of the entire harmonic filter bank instead of the individual units.

Capacitance tolerances for series capacitors are specified on a per phase basis for the entire bank in IEEE 824.

Discharge Resistors. Under certain conditions, when line voltage is removed from a power capacitor, the possibility exists that the unit will retain an extremely high charge even days later. This characteristic of retaining such a charge is demonstrated by the high efficiency and low-loss operation of

a power capacitor. To eliminate this hazard, all power capacitors contain internal-discharge resistors. This resistor assembly will reduce the terminal voltage from line voltage to 50 V within 5 min of deenergization for a capacitor rated higher than 600 V ac, and within 1 min for capacitors rated 600 V ac or less.

Capacitor Unit Losses. Present-day high-voltage capacitors operate at a lower watts loss per kvar than do low-voltage capacitors. For example, capacitors that utilize an *all-film dielectric* may operate with losses of less than 0.1 W per kvar. Low-voltage capacitors using *metalized polypropylene dielectric* may experience losses of near 0.5 W per kvar.

The cost of operating high-voltage capacitors is lower per kvar than low-voltage capacitors because of the basic difference in dielectric materials which allows high-voltage capacitor to be operated more efficiently.

Capacitor Tank Rupture. Capacitor tank rupture of high-voltage capacitors will occur if the total energy applied to the capacitor unit under failure conditions is greater than the ability of the capacitor tank to withstand such energy. Tank-rupture curves are essential to the correct selection of fuse links for overcurrent protection of externally fused capacitors. A typical tank rupture curve is shown in Fig. 10-104.

Temperature. Although very efficient, power capacitors do consume some power and generate heat. This heat must be adequately ventilated when enclosed or exposed to higher than normal ambient temperatures.

The maximum operating temperature for power capacitors is specified in IEEE 18 for various mounting arrangements. The minimum operating temperature is -40°C .

Capacitor applications must be designed for adequate overvoltage and “corona” capabilities, since the partial discharge (corona) characteristics vary with temperature. It is necessary to consider the full range of temperatures to which the capacitors will be exposed, in both the energized and deenergized modes.

10.5.3 Shunt Capacitors

The most common application of power capacitors is shunt connected capacitors and they are either energized continuously or switched on and off during load cycles.

Common Shunt Capacitor Connections. Figure 10-105 shows four of the most common capacitor connections: 3-phase grounded wye, 3-phase ungrounded wye, 3-phase delta, and single phase. Grounded or ungrounded wye connections are usually made on medium and high-voltage systems, whereas delta and single-phase connections are usually made on low-voltage systems.

Grounded-wye capacitors can bypass some line surges to ground and therefore exhibit a certain degree of self-protection from transient voltages and lightning surges. The grounded-wye connection also provides a low impedance path for harmonics.

If the capacitors are electrically connected ungrounded-wye, the maximum fault current would be limited to 3-times line current. If the available fault current exceeds the tank rupture curve the use of current limiting fuses must be considered.

Low-Voltage Shunt Capacitors. Low-voltage shunt capacitors are typically applied in industrial power systems, in voltage ratings from 240 to 600 V over the range of 2.5 to 100 kvar 3-phase. They can be used for power factor improvement and voltage support on low voltage systems where adjustable speed drives, power electronics, and other industrial equipment are applied.

Low-voltage capacitors made with metalized polypropylene are self-healing. That is, the conductors consist of very thin layers of metal deposited on the film dielectric. In the event of short circuit, the conductor vaporizes to eliminate the fault with negligible loss of capacitance and continued operation. External fuses are not required on these units although some users add them for additional protection of their connections and ground faults.

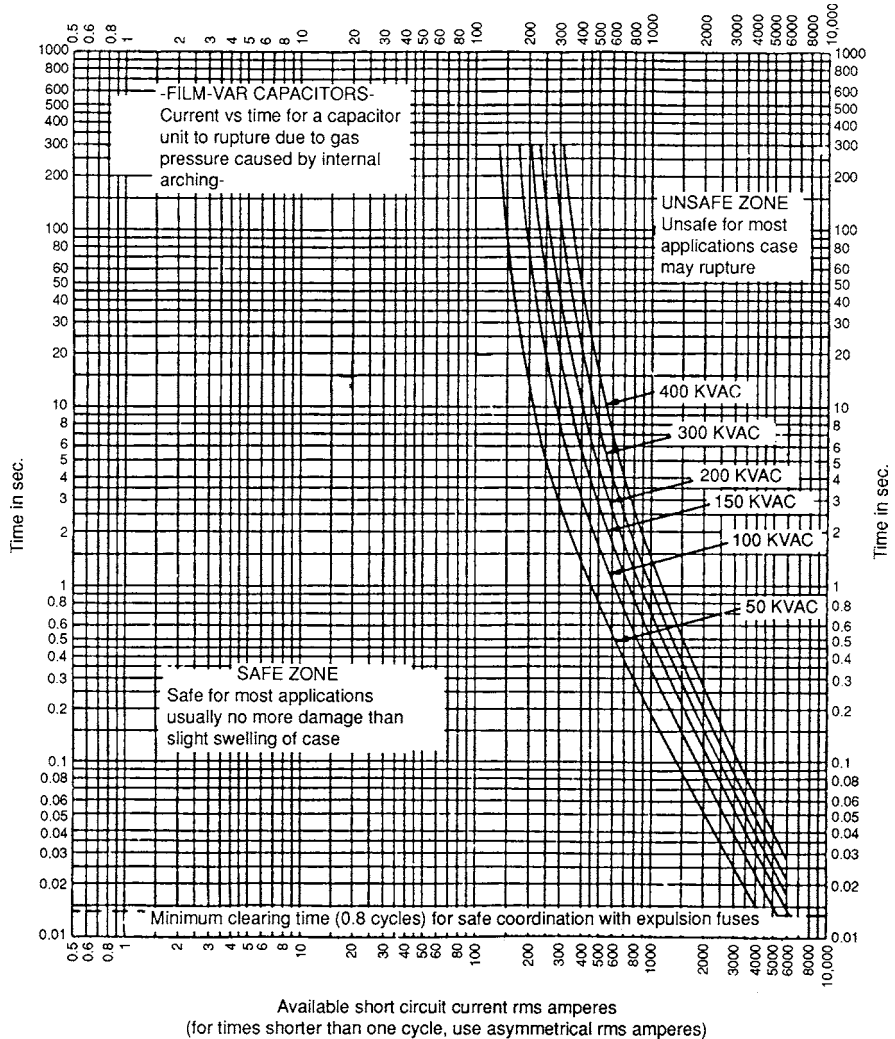


FIGURE 10-104 High-voltage capacitor tank-rupture curve.

Distribution Shunt Capacitors. Capacitors for overhead distribution systems can be pole-mounted typically in banks of 300 to 3600 kvar at nearly any system voltage up to 34.5 kV phase-to-phase. Pad-mounted capacitor equipments are used for underground distribution systems in the same range of sizes and voltage ratings. See Fig. 10-106 for a typical pole-mounted capacitor bank.

The majority of the power capacitor equipment installed on medium voltage distribution systems is connected grounded wye. With the grounded-wye connection, tanks and frames of switching equipment are at ground potential. This provides increased personnel safety. Grounded-wye connections provide for faster fuse operation in case of a capacitor failure.

Distribution shunt capacitors can be protected with individual unit fuses or group fused. Tank rupture curves are essential to the correct selection of fuse links for overcurrent protection of any capacitor installation. Fuse selections should be based upon the coordination of the fuse-link maximum clearing curve (Fig. 10-107) and the high-voltage capacitor tank-rupture curve (Fig. 10-104).

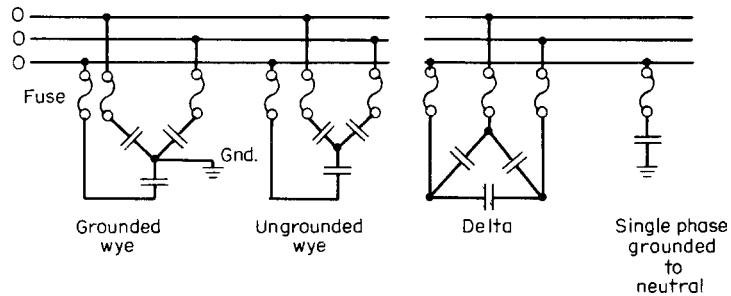


FIGURE 10-105 Common methods for connecting power-factor capacitors.

Several fundamental principles must be observed in the selection of fuses for capacitor applications:

1. The fuse link must be capable of continuously carrying 135% of the nominal capacitor current as a minimum. Higher values may be required when high harmonic currents are present.
2. The fuse cutout must have sufficient interrupting capacity to successfully handle the available fault current, clearing voltage, and available energy before the capacitor tank ruptures.
3. The fuse link must withstand, without damage, the normal transient current during bank energization or de-energization. Similarly, it must withstand the capacitor unit's discharge current during a terminal-to-terminal short.
4. For ungrounded-wye banks, maximum fault current is usually limited to 3 times normal line current. The fuse link must clear within 5 min at 95% of available fault current.

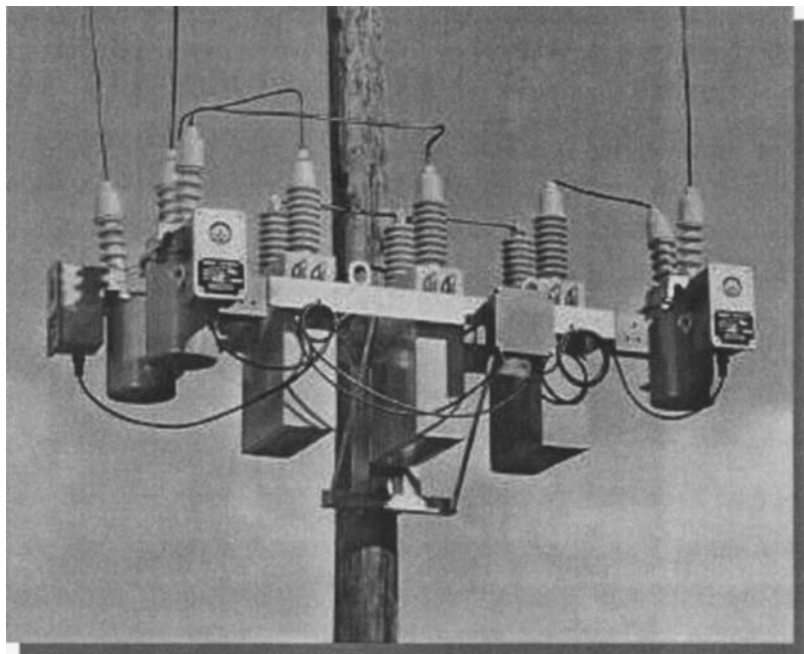


FIGURE 10-106 Typical pole-mounted distribution capacitor bank.

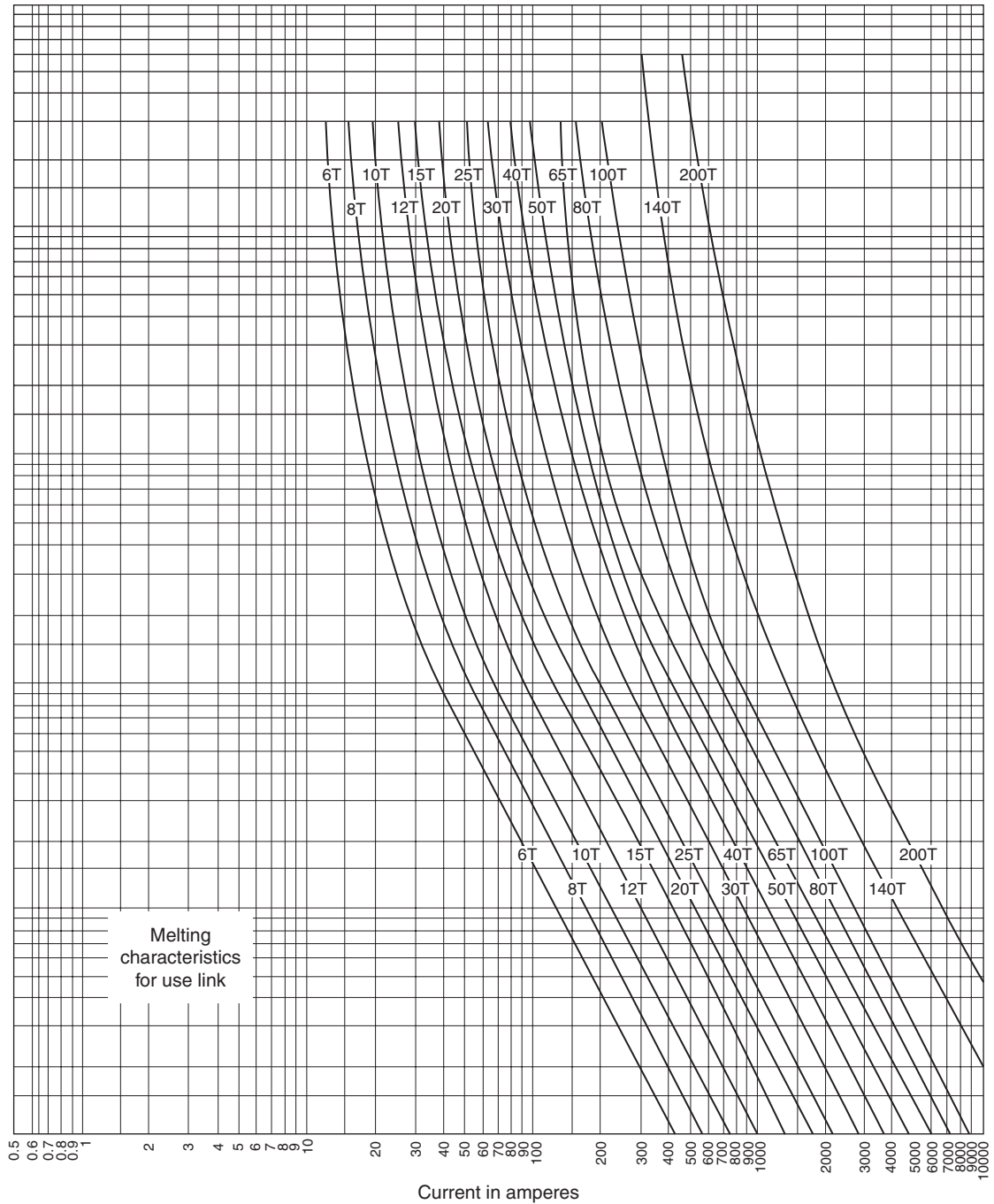


FIGURE 10-107 Typical time-current curve for an expulsion fuse.

5. For effective capacitor protection, maximum asymmetric rms fault current should not exceed the current value at the intercept point of the capacitor tank-rupture time-current characteristic (TCC) curve and the minimum time shown on the fuse maximum-clearing TCC curve.
6. The maximum-clearing TCC curve of the fuse link must coordinate with the tank-rupture TCC curve of the capacitor unit.

For more detailed information on the application of shunt capacitors in distributions systems refer to IEEE 1036⁴. For application guidance on external fuses for shunt capacitors refer to IEEE C37.48⁵.

Substation Shunt Capacitor Banks. Substation shunt capacitor banks are usually installed grounded-wye, ungrounded-wye or delta. Delta connected shunt banks are usually at lower voltages, for example, 2400 V. Grounded-wye shunt capacitor bank installations are typically more economical than ungrounded-wye banks because the neutral does not have to be insulated for the system voltage. This advantage increases with system voltage. Also, the transient recovery voltages (TRV) for grounded-wye banks are less than ungrounded-wye, thus reducing the TRV requirements for switching equipment.

A disadvantage of grounded-wye shunt capacitor banks is that there is a possibility of high-frequency switching transients in the ground grid that could induce transients in relay and control cables resulting in erroneous relay operations.

Ungrounded-wye shunt capacitor banks may be applied at any system voltage as long as the insulation and TRV requirements are considered.

For shunt banks that have only one series group, it is more desirable to install an ungrounded wye bank. In a grounded wye bank with one series group, if one unit completely shorts and the phase-to-ground fault current is too high it will rupture the unit. With an ungrounded-wye bank, the fault current is limited to three times the bank current.

There are three common substation shunt capacitor bank types utilized today: externally fused, internally fused, and fuseless. These three types are briefly described in this section.

For more detailed information on the application and protection of substation shunt capacitor banks, refer to IEEE 1036⁴, IEEE C37.99⁶ and IEEE C37.48⁵.

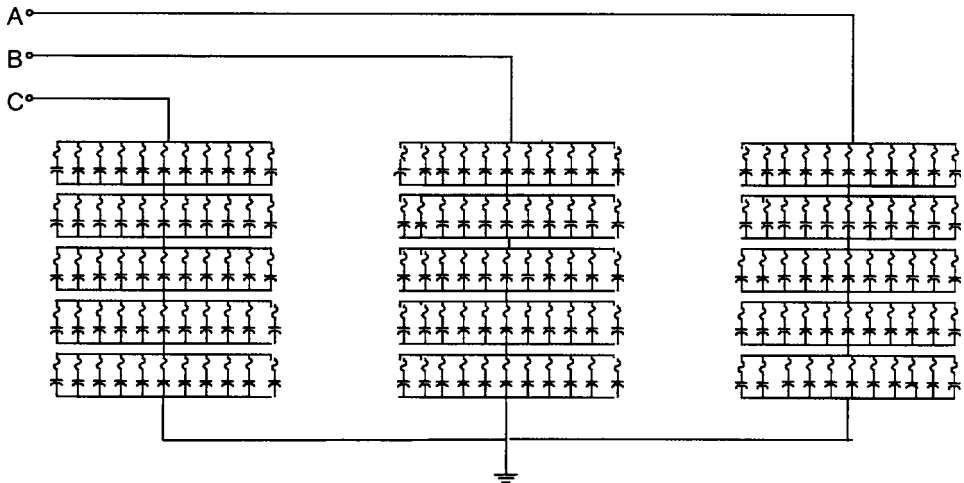
Externally Fused Shunt Capacitor Banks. An externally fused shunt capacitor bank is made up of series groups of parallel connected capacitor units. Each unit is individually fused with an expulsion or current-limiting fuse mounted external to the unit. A typical schematic for an externally fused shunt capacitor bank is shown in Fig. 10-108.

A capacitor unit voltage rating is chosen usually to limit the number of series groups to as few as possible, while achieving the desired voltage rating of the bank. This usually results in the simplest design and highest sensitivity for unbalance protection.

Fewer series groups may mean more units in parallel in each series group. This could require the use of current limiting unit fuses instead of expulsion type fuses. When a unit fails in an externally fused bank the other units in parallel with it will discharge into the failed unit through its individual fuse. When the energy from this discharge exceeds the energy capability of an expulsion fuse, the user will have to specify current limiting fuses which have a higher energy capability. To avoid this, the user can specify a lower voltage rating for the units and design the bank with more series groups and fewer units in parallel. Another option is to split the bank in two sections, called a double-wye configuration. For principles of fuse selection for the individual units, refer to the earlier section on distribution shunt capacitors. For more detailed guidance on fusing refer to IEEE C37.48⁵ and IEEE C37.48.1⁷.

It is also important to keep a minimum number of units in parallel in each series group. When a fuse operates and removes a unit from a series group the voltage will increase on the remaining units in parallel with it. It is desirable to have enough units in parallel that the 110% overvoltage capability will not be exceeded for the loss of one unit. There are curves available to help determine the voltage on remaining capacitor units in a series group based on the percentage of capacitor units removed from the series group. These curves are located in IEEE 1036⁴, which covers the application of shunt capacitors. The curves were previously located in an appendix of IEEE 18¹, but were removed from the 2002 revision.

A typical externally-fused shunt capacitor bank is shown in Fig. 10-109.



5 series groups per phase
11 parallel units in each series group

FIGURE 10-108 Schematic of a typical externally fused shunt capacitor bank.

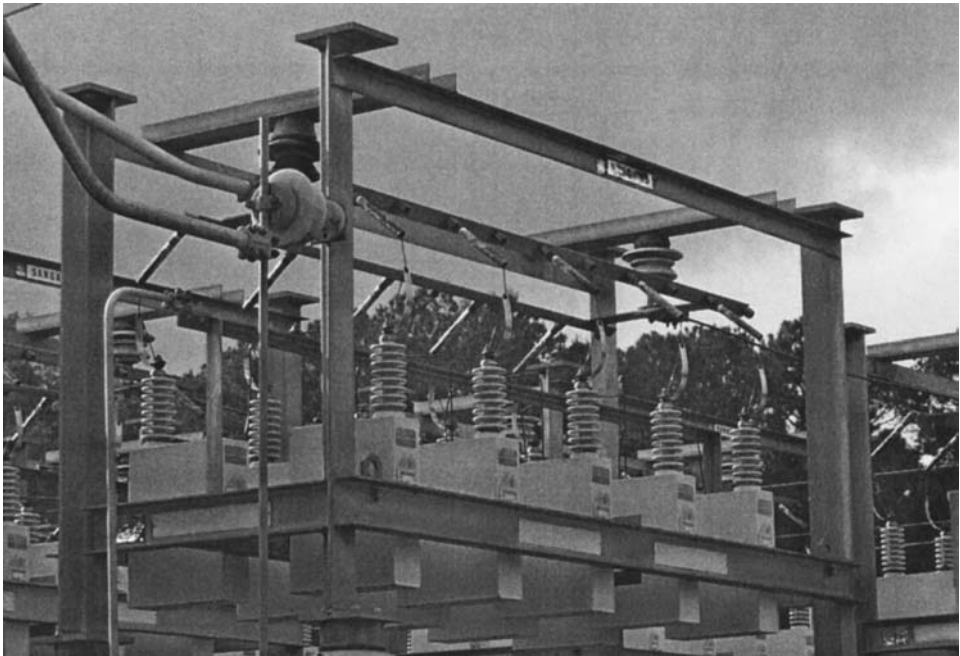


FIGURE 10-109 Typical externally fused shunt capacitor bank.

Internally Fused Shunt Capacitor Banks.

An internally fused capacitor bank is made up of series and/or parallel connected capacitor units. The units are made up of capacitor elements connected in series/parallel combinations to achieve the desired rated voltage and kvar rating. A fuse is put in series with each element inside the unit case. An internally fused unit is shown schematically in Fig. 10-110. When a failure of a capacitor element occurs, its individual fuse will operate to isolate the element. The unit typically has a large number of elements in parallel so that the loss of one element does not have a significant increase in voltage on the remaining elements in parallel with the failed element. The kvar rating of internally fused units is typically much larger than externally fused units.

Internally fused capacitor banks typically have fewer units in parallel and more series groups than externally fused capacitor banks. A typical schematic for an internally fused shunt capacitor bank is shown in Fig. 10-111. It is usually desirable to have at least two units

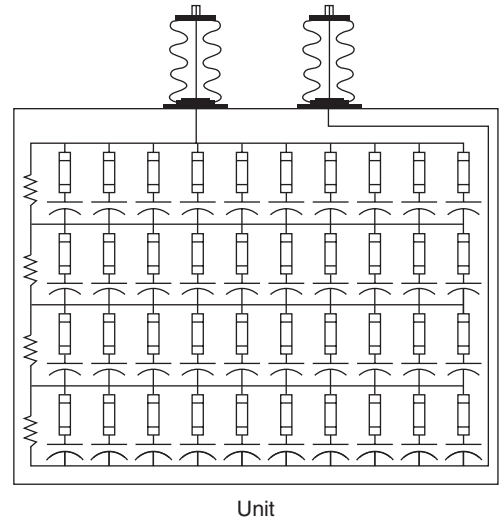


FIGURE 10-110 Internal connection diagram of a typical internally fused capacitor unit.

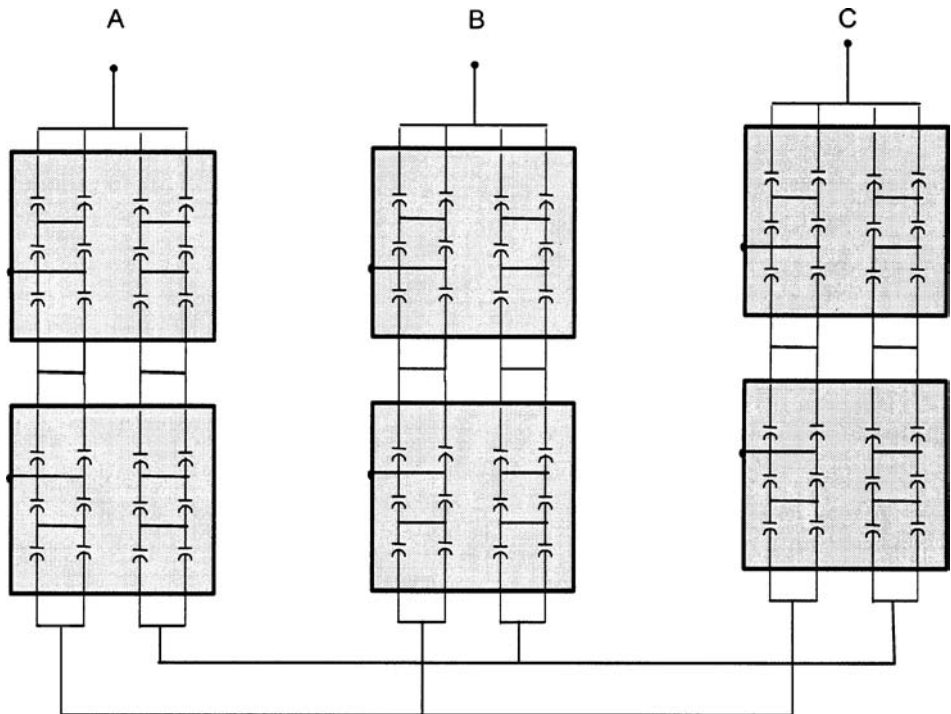


FIGURE 10-111 Schematic of a typical internally fused shunt capacitor bank.

in parallel. If one unit has a large number of failed elements, the unit in parallel will help keep down the terminal-to-terminal voltage. The maximum number of capacitor units that can put in parallel is determined by the energy capability of the internally fused unit.

A typical internally fused capacitor bank is shown in Fig. 10-112.

Fuseless Shunt Capacitor Banks. A fuseless shunt capacitor bank is not simply an externally fused capacitor bank with the fuses removed. It is a different arrangement of capacitor units designed to operate without fuses. A fuseless shunt capacitor bank is made up of units connected in series phase-to-ground or phase-to-neutral. This arrangement of units is called a series string. The unit voltage is selected to achieve the desired voltage rating of the bank. The kvar rating of the unit is chosen to achieve a desired reactive output per each string. Then the bank kvar rating can be increased in these increments by putting multiple series strings of capacitors in parallel. A schematic for a typical fuseless

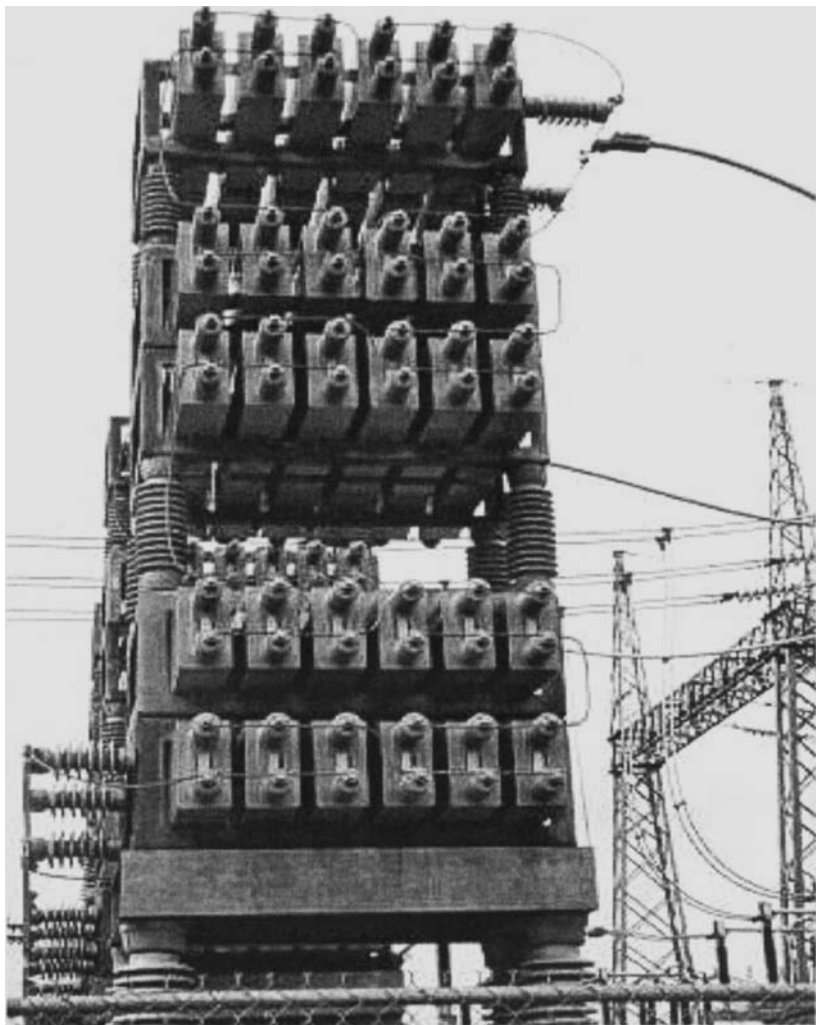


FIGURE 10-112 Example of an internally fused shunt capacitor bank.

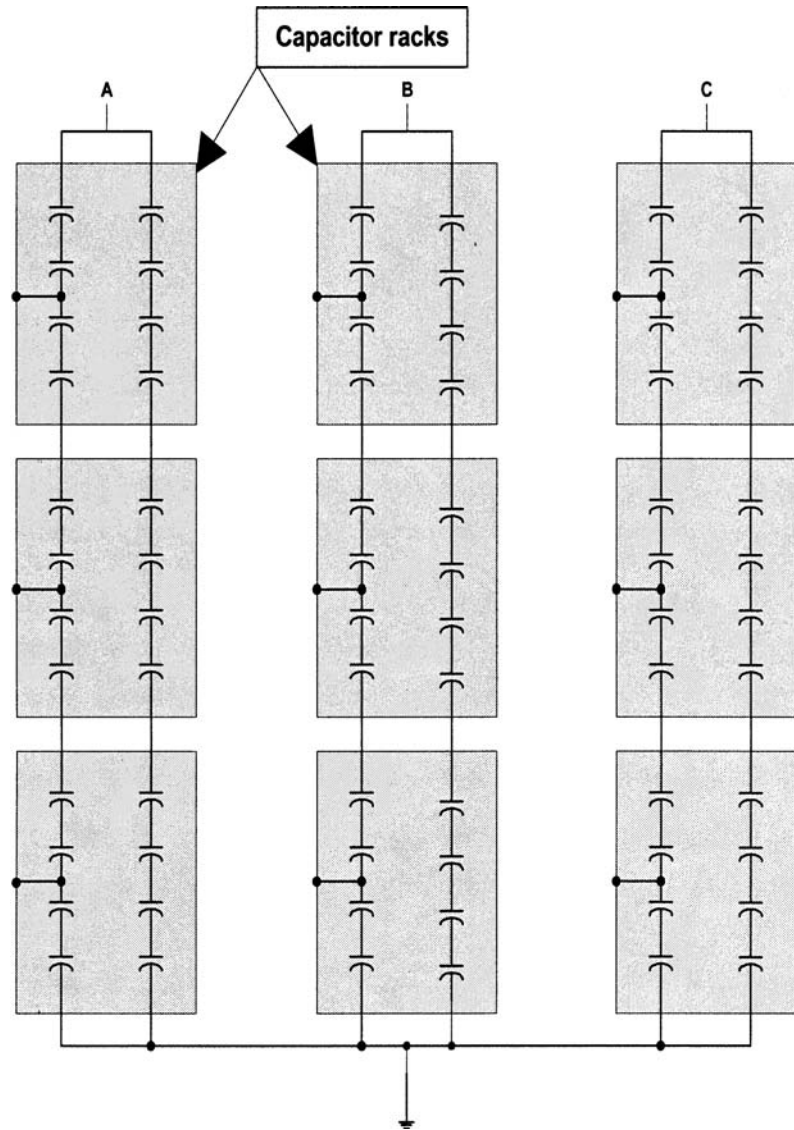


FIGURE 10-113 Schematic of a typical fuseless shunt capacitor bank (Two parallel series strings of twelve units in series.)

shunt capacitor bank is shown in Fig. 10-113. The fuseless capacitor bank is made up of parallel groups of series units, while the externally fused bank is made up of series groups of parallel units.

Fuseless capacitor bank installations were made possible with the design of the *all-film dielectric* capacitor unit, described earlier in the Sec. 10.5.2. The common failure mode of an element in an all-film dielectric unit is for it to fail shorted. When it shorts, the aluminum foil melts and welds together creating a low resistance point that will continue to carry the current through the capacitor indefinitely.

Typically, kvar ratings of units in fuseless capacitor banks are larger than units used in externally fused capacitor banks. This is because fuseless banks do not have the same design consideration of keeping a minimum number of units in parallel as discussed previously for externally fused banks. With the units connected in series, if one element in a unit fails, the voltage will increase proportionately across the remaining elements in series with it. For example, if a unit has 10 series groups of elements inside each unit and there are 5 units in a series string, then there will be 50 elements in series phase-to-neutral. If one element fails then the voltage on the remaining elements in series will increase by 1/50th of the total phase-to-neutral voltage. The unbalance protection would usually be set to trip when the overvoltage has exceeded the 110% capability of the elements.

When designing a fuseless bank and choosing the rated voltage and kvar of the units, keep in mind the continuous current capability and the transient current capability of the units. With the series string design of a fuseless bank, there are typically fewer parallel paths for these currents.

A typical fuseless shunt capacitor bank is shown in Fig. 10-114.

Harmonic filter shunt capacitor banks. Non-linear devices or loads, such as rectifiers and arc furnaces, can create harmonic distortion on the power system. Excessive harmonic voltages or currents can create problems for equipment and the electrical system in general. One common way to eliminate these harmonics is to install a passive harmonic filter near the device or load to shunt some of the harmonic current and thereby reduce the harmonic current flowing into the system. A schematic for a typical harmonic filter capacitor bank is shown in Fig. 10-115. The need for harmonic filters can be on low, medium, or high voltage electrical systems.

For low-voltage systems, the dry-type, metalized film capacitors are typically used and an inductor is used to create an LC circuit approximately tuned to the frequency of the harmonic being generated.

For medium and high voltage systems, the all-film, oil-filled dielectric capacitors are commonly used and, depending on the system voltage, a dry-type or oil-filled reactor is used to create an LC circuit approximately tuned to the frequency of the harmonic being generated. The capacitor portion for medium- and high-voltage harmonic filter banks can be externally fused, internally fused, or fuseless.

Harmonic filter capacitor banks may look similar to conventional shunt capacitor banks, but there are different criteria to consider when designing a harmonic filter bank. In general, the following should be considered when designing a harmonic filter bank:

1. Reactive power (kvar) requirements
2. Harmonic limitations
3. Normal system conditions, including ambient harmonics
4. Normal harmonic filter conditions
5. Contingency system conditions, including ambient harmonics
6. Contingency harmonic filter conditions

For detailed guidance in designing low, medium, and high voltage harmonic filter capacitor banks refer to IEEE 1531³.

A typical harmonic filter shunt capacitor bank is shown in Fig. 10-116.

Protective Relaying for Shunt Capacitor Banks. Protection of shunt capacitor banks includes bank and system protection schemes.

Bank protection schemes usually involve some type of unbalance protection to trip the bank for overvoltage due to unit (element) failures, overcurrent protection for faults in the bank other than in units, and phase overcurrent or negative sequence protection for rack-to-rack flashovers in a phase-over-phase bank design.

System protection schemes can involve phase voltage relays for system overvoltage conditions, bus overcurrent, ground-overcurrent, or differential protection for faults in the capacitor installation

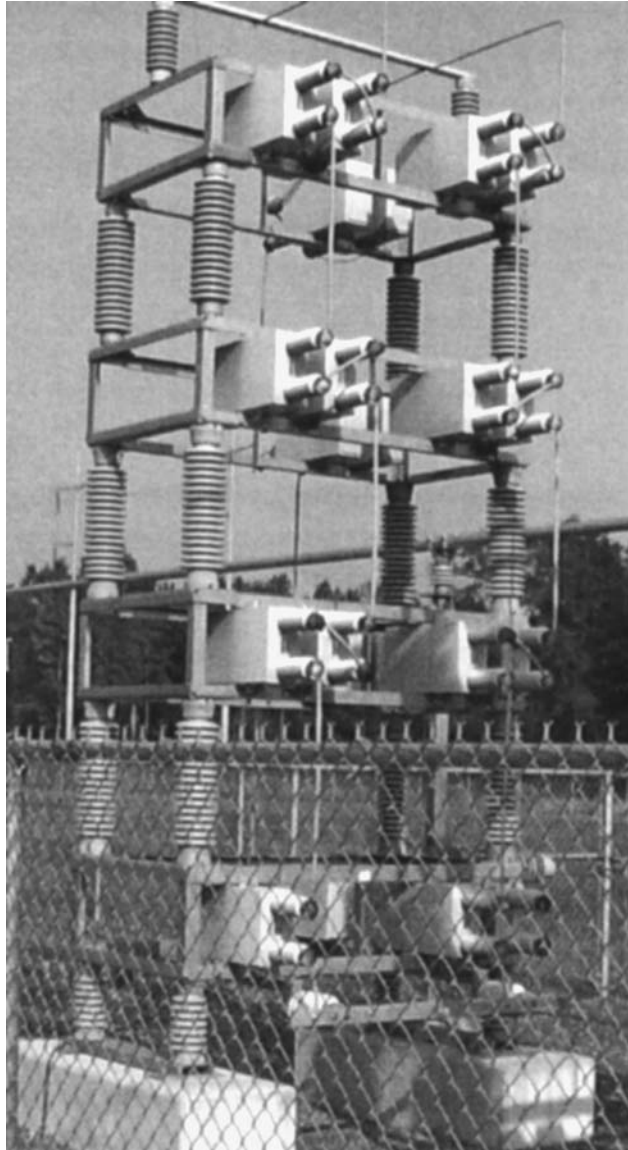


FIGURE 10-114 Example of a fuseless shunt capacitor bank.

or major capacitor bank failure, harmonic overload protection for excessive harmonic currents in the system, undervoltage relays for system outages, and breaker failure relays.

The following is a list of basic considerations for protection of shunt capacitor banks:

1. Type of shunt capacitor bank (externally fused, internally fused, or fuseless)
2. Bank connection (grounded wye, ungrounded wye, double wye, etc.)

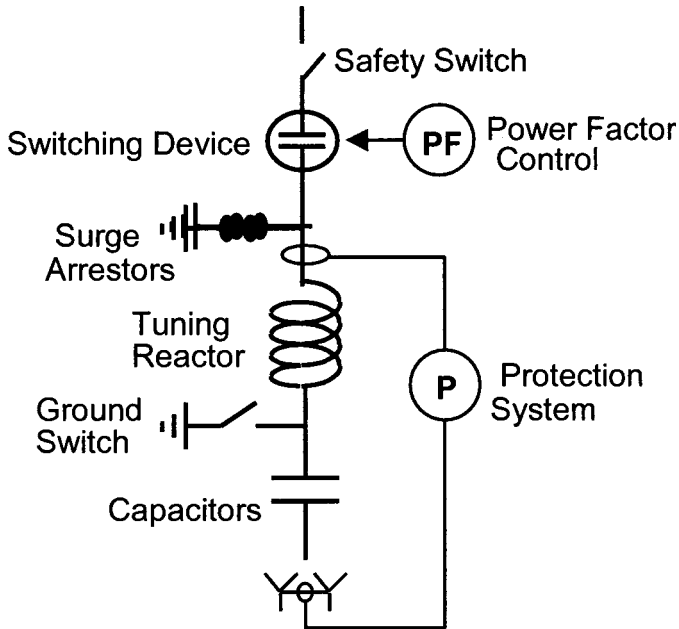


FIGURE 10-115 Typical schematic of a harmonic filter shunt capacitor bank.



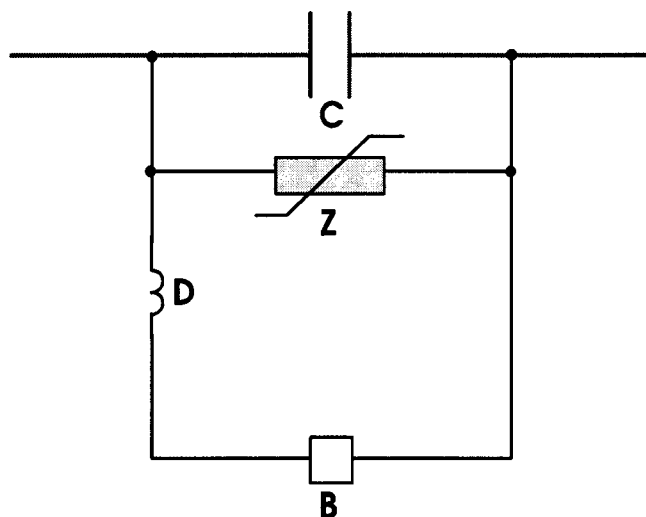
FIGURE 10-116 Typical high-voltage harmonic filter shunt capacitor bank.

3. Capacitor bank design and arrangement of units
4. Normal and contingency system conditions
5. Point of connection to the power system
6. Capacitor unit capabilities
7. Overvoltage on remaining capacitor units
8. Installation grounding for grounded banks (single-point or peninsula grounding)

For detailed guidance on the protection of conventional and harmonic filter shunt capacitor banks refer to IEEE C37.99⁶.

10.5.4 Series Capacitor Banks

Fixed (Conventional) Series Capacitors. A fixed series capacitor bank is an assembly of different components inserted in series with a power line to reduce the apparent reactance, increase the power transfer capability and improve system stability. The major components of a fixed series capacitor bank include capacitors, varistors, bypass gaps, bypass switches, discharge current limiting reactors, insulated structures, and protection and control systems. The inserted reactance is primarily established by the reactance of the capacitors. A schematic for a typical fixed series capacitor bank is shown in Fig. 10-117. The capacitors can be of the externally fused, internally fused, or fuseless design. Series capacitor banks are more commonly applied on higher voltage transmission systems, but they have been applied on distribution systems. See Fig. 10-118 for a typical high-voltage series capacitor bank.



C Capacitor bank
Z Metal oxide varistor
D Discharge damping reactor
B By-pass breaker

FIGURE 10-117 Schematic of fixed conventional series capacitor bank.

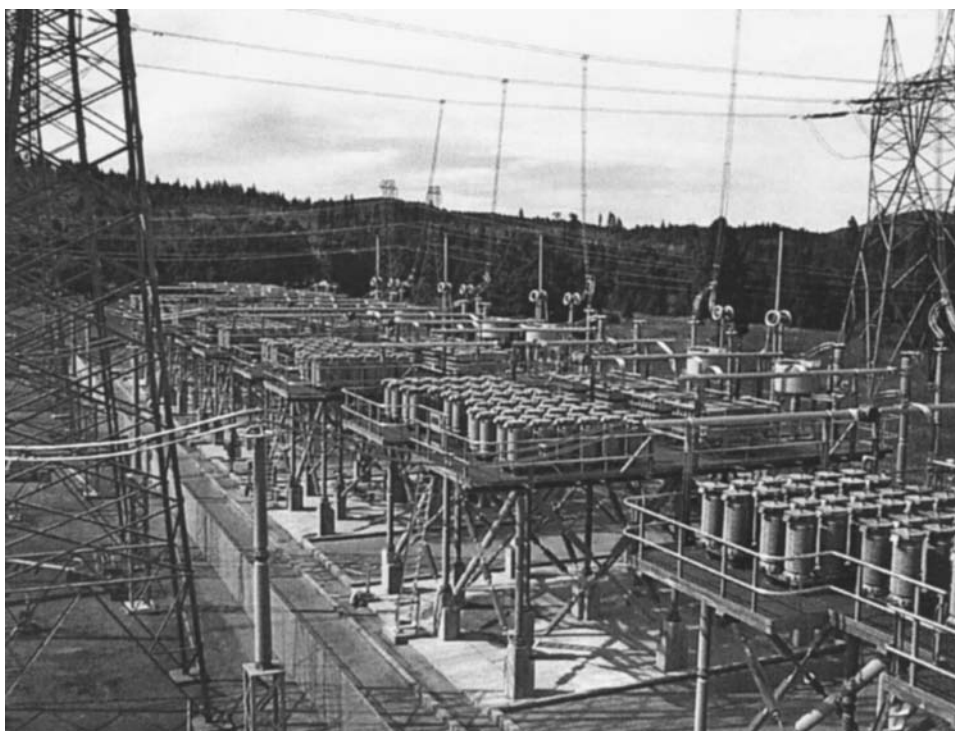


FIGURE 10-118 Typical fixed series transmission series capacitor bank.

For detailed information on the design, application, and protection of fixed transmission series capacitor banks, refer to IEEE 824^{2,8}. There currently is also an IEEE working group preparing a guide for the specification of fixed transmission series capacitor banks.

For information on distribution series capacitors the user can refer to an IEEE Transactions paper written by the IEEE Series Capacitor Working Group⁹.

General information about the protection of series capacitor banks can be found in the IEEE Special Publication TP-126-0¹⁰. There currently is also an IEEE working group preparing a guide for protection of transmission line series capacitors. When published, the document will be designated IEEE C37.116, *Guide for Protective Relay Application of Transmission-Line Series Capacitors*.

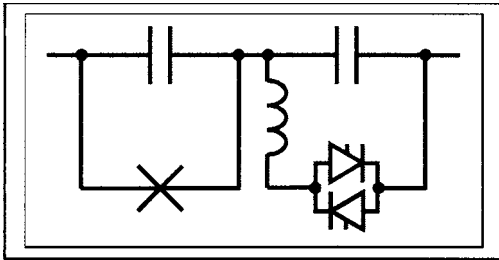


FIGURE 10-119 Typical schematic of a thyristor-controlled series capacitor bank.

Thyristor-Controlled Series Capacitors (TCSC). A thyristor-controlled series capacitor (TCSC) is a series capacitor bank paralleled with a thyristor-controlled reactor. In the controlled operation mode, periodic gating results in thyristor currents at a frequency higher than the power frequency which add with the line current. This boosts the capacitor voltage beyond the level that would be obtained by the line current alone. Also, controlled operation provides dynamic var compensation to control line current or through power. A schematic for a TCSC bank is shown in Fig. 10-119. The ability to

control TCSC reactance rapidly provides a degree of transient stability and subsynchronous resonance mitigation, which is an advantage a TCSC has over a fixed series capacitor bank. A typical TCSC is shown in Fig. 10-120.

For detailed information on thyristor-controlled series capacitors, refer to IEEE 1534¹¹.

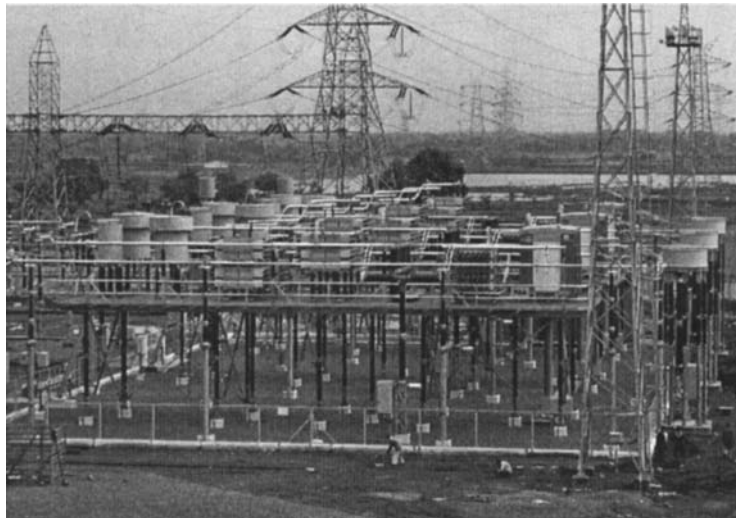


FIGURE 10-120 Typical thyristor-controlled series capacitor bank.

10.5.5 Capacitor Switching Equipment

This chapter will not go into the details of specifying equipment used to switch and protect capacitor banks. But a bibliography of documents providing rating, application, and specification information on switching equipment for shunt and series capacitors is provided at the end of this chapter for the user's reference.

REFERENCES

1. IEEE 18, *Standard for Shunt Power Capacitors*.
2. IEEE 824, *Standard for Series Capacitor Banks in Power Systems*.
3. IEEE 1531, *Guide for Application and Specification of Harmonic Filters*.
4. IEEE 1036, *Guide for the Application of Shunt Power Capacitors*.
5. IEEE C37.48, *Guide for the Application, Operation, and Maintenance of High-Voltage Fuses, Distribution Enclosed Single-Pole Air Switches, Fuse Disconnecting Switches, and Accessories*.
6. IEEE C37.99, *Guide for the Protection of Shunt Capacitor Banks*.
7. IEEE C37.48.1, *Guide for the Operation, Classification, Application, and Coordination of Current-Limiting Fuses with Rated Voltages 1-38 kV*.
8. P. M. Anderson and R. G. Farmer, *Series Compensation of Power Systems*, PBLSH! Inc., 1996, Internet-<http://www.pblsh.com/CDsBooks>.
9. "Considerations for the application of series capacitors to radial power distribution circuits," IEEE Transactions on Power Delivery, vol. 16, Issue 2, April 2001, Pages:306–318.
10. IEEE Special Publication TP-126–0, *Series Capacitor Bank Protection*.
11. IEEE 1534, *Recommended Practice for Specifying Thyristor Controlled Series Capacitors*.

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Standards for Equipment used to Switch Power Capacitors

- IEEE 824, *Standard for Series Capacitor Banks in Power Systems*.
- IEEE 1247, *Standard for Interrupter Switches for Alternating Current, Rated above 1000 volts*.
- IEEE C37.04, *Standard Rating Structure for AC High-Voltage Circuit Breakers*.
- IEEE C37.012, *Application Guide for Capacitance Current Switching for AC High-Voltage Circuit Breakers*.
- IEEE C37.016, *Standard for Circuit Switchers*.
- IEEE C37.66, *Standard Requirements for Capacitor Switches for AC Systems, 1–38 kV*.
- IEC 62271-109, *Alternating current series capacitor by-pass switches*.

10.6 FUSES AND SWITCHES

BY JON HILGENKAMP

10.6.1 Fuses

General Classifications. Fuses can be classified into three categories. The first is low-voltage fuses operating up through 600 V ac. Most devices are tested and approved by Underwriters' Laboratories, Inc., and are marketed in a wide variety of characteristics and physical configurations. The second classification is medium-voltage through 69 kV, and the third is high-voltage fuses through 500 kV. These fuses are used by electric utilities to protect transmission-distribution-class equipment and by large industrial complexes which have their own electrical distribution systems.

TABLE 10-13 Class of Low-Voltage Fuses and Applicable Standards

Fuse class	Standard
Plug fuses	UL 198F
Radio and appliances	UL 1417
Mine duty	UL 198M
DC fuses	UL 198L
H	UL 198B and ANSI C97.1
G, J, L	UL 198C and ANSI C97.1
K	UL 198D and ANSI C97.1
R	UL 198E
T	UL 198H

Low-Voltage Fuses. Low-voltage fuse standards are established by ANSI, NEMA, or Underwriters' Laboratories (see Table 10-13). Their characteristics include a voltage class, an ampere rating, and an interrupting rating and, for some classes of fuses, a current-limiting rating. Cartridge fuses are classified in the following voltage classes: not over 250 V ac, not over 300 V ac, and not over 600 V ac. Fuses should not be used for dc applications unless recommended by the manufacturer. Most low-voltage fuses must be used in accordance with the National Electrical Code. Exceptions include those

used in ships, railways, aircraft, and automotive vehicles other than mobile homes and recreational vehicles.

The standard lines of low-voltage fuses are available in several steps of ampere capacity, each of which is a different physical size (see Table 10-14).

A minimum of 10,000-A interrupting capacity is typical in low-voltage fuses, but some sizes and types are capable of interrupting up to 200,000 A ac or 100,000 A dc. The interrupting rating is the highest rms symmetric alternating current which the fuse can interrupt at rated voltage.

Low-voltage current-limiting fuses are designed so that non-current-limiting fuses cannot be inserted into the fuse holder as a direct replacement. Thus, Class K fuses which are interchangeable with Class H fuses are not permitted the "current-limiting" label.

A low-voltage current-limiting fuse successfully and safely interrupts all available currents within its specified interrupting rating and, within its current-limiting range, limits the clearing time at rated voltage to an interval equal to or less than the first major current loop. These fuses also limit peak let-through current to a value less than the normal peak current that would be possible without current-limiting availability. The current-limiting characteristics of current-limiting fuses are expressed by two electrical measurements: (1) maximum peak let-through current, the maximum instantaneous value of current passed by the fuse during time of operation; and (2) maximum clearing Pt (amperes-squared-seconds), an expression of the energy available as a result of current flow during the clearing time of operation.

Limiters are time-delay fusible connectors designed to be installed in low-voltage network-mains cables at street-junction points. They are rated in cable sizes and have time-current characteristics to (1) allow the cable fault to burn itself clear if it does so promptly, without blowing the limiter; (2) blow before the cable insulation away from the fault is damaged and prevent the failure from spreading beyond the junction; and (3) obtain adequate selectivity so that, when installed in a network, only those limiters connected to the faulted cable blow (see Fig. 10-121 for limiter characteristics).

The usual applications of limiters are at the street-corner junctions of low-voltage network mains, multiple-transformer secondary cables, multiple-service cables, and intervault ties of building interior networks.

In recent years, combinations of low-voltage circuit breakers and low-voltage current-limiting fuses have been devised to provide improved short-circuit protection, especially on motor branch circuits where contactors have low interrupting ratings.

Medium- and High-Voltage Fuses. A medium-voltage fuse is defined as any fuse (above 600 V and less than 69 kV) or fuse device used to isolate an electric short circuit

TABLE 10-14 Typical Dimension Grouping of Fuses

Class	Volts	Amperes
G	300	0–15
G	300	16–20
G	300	21–30
G	300	31–60
H, K	250, 600	0–30
H, K	250, 600	31–60
H, K	250, 600	61–100
H, K	250, 600	101–200
H, K	250, 600	201–400
H, K	250, 600	401–600
L	600	601–800
L	600	801–1200
L	600	1201–1600
L	600	1601–2000
L	600	2001–2500
L	600	2501–3000
L	600	3001–4000
L	600	4001–5000
L	600	5001–6000

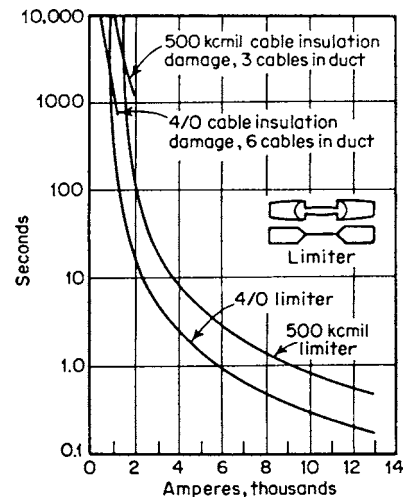


FIGURE 10-121 Time-current characteristics of low-voltage limiters for No. 4/0 and 500 Mcmil network cables.

from an electrical distribution system. A *high-voltage fuse* is defined as any fuse rated above 69 kV and less than 230 kV used for this same purpose. Specific classes of fuses or fused devices are

- Enclosed cutouts and fuses
- Open cutouts and fuses
- Open-link cutouts and fuses
- Current-limiting fuses
- Power fuses
- Oil-immersed protective links

See Table 10-15.

TABLE 10-15 Classes of High-Voltage Fuses or Fused Devices and Applicable Standards

Class device	Standard
Distribution cutouts and fuse links	ANSI C37.42
Distribution oil cutouts and fuse links	ANSI C37.44
Power fuses	ANSI C37.46
Current-limiting fuses	ANSI C37.47

These fuses are used to protect potential transformers, distribution or power transformers, and lateral taps from main distribution feeder circuits. They are often used as sectionalizing devices on main feeder circuits. The ampacity and interrupting rating of these devices range up to 720 A, 500 mVA at 14,400 V, and 250 A, 2000 mVA at 138,000 V. Fuses are generally used in electrical series with other fuses or circuit-protective devices.

Care must be taken in coordinating the time-

current characteristics for proper isolation of the electric circuit during fault and overload conditions.

Distribution fuse links for use with expulsion cutouts are available with many different time-current characteristics. Figure 10-122 shows the minimum melting time-current characteristics for ANSI Type K fuse links.

In an effort to standardize fuse-link characteristics, ANSI has adopted time-current characteristics for two basic fuse-link types: Type K (fast) and Type T (slow). These fuse links are designed so as to have the same time-current characteristics regardless of manufacturer. A wide variety of non-standardized fuse-link characteristics are also available. Fuse-link characteristics are usually based on tests at an ambient temperature of 25°C and no initial load. For characteristics at other ambients or for preloading variations, consult the individual manufacturer.

The characteristics of various medium- and high-voltage protective devices used on distribution power systems are

1. Expulsion cutouts

- a. *Open type*: 20-kA asymmetric maximum interrupting current (IC), 5 to 35 kV, violent in operation at high faults, low cost, both initial and refusing. Maximum continuous-current rating of 200 A; can be fitted with a solid blade for conversion to a disconnect switch with a rating of 300 A. Figure 10-123 shows a typical open-type cutout.
 - b. *Enclosed type*: 8- to 10-kA asymmetric maximum interrupting current, used primarily where safety codes dictate use. Enclosed cutouts are no longer manufactured and are being replaced with open-type cutouts.
 - c. *Open link*: 1200-A maximum interrupting current, 50-A maximum continuous current, applied on rural lines and/or small transformers.
2. *Oil cutouts*: Considerable application in the past, especially in underground vaults; however, low interrupting current now poses serious underrating problems.
 3. *Liquid fuses*: Nonviolent, low interrupting current (8 to 10 kA maximum).
 4. *Power fuses*: Reduced arc energy, somewhat less violent than cutouts on high faults, rated to 20-kA interrupting current; both initial purchase and replacement expensive. Figure 10-124a shows an indoor-type power fuse.

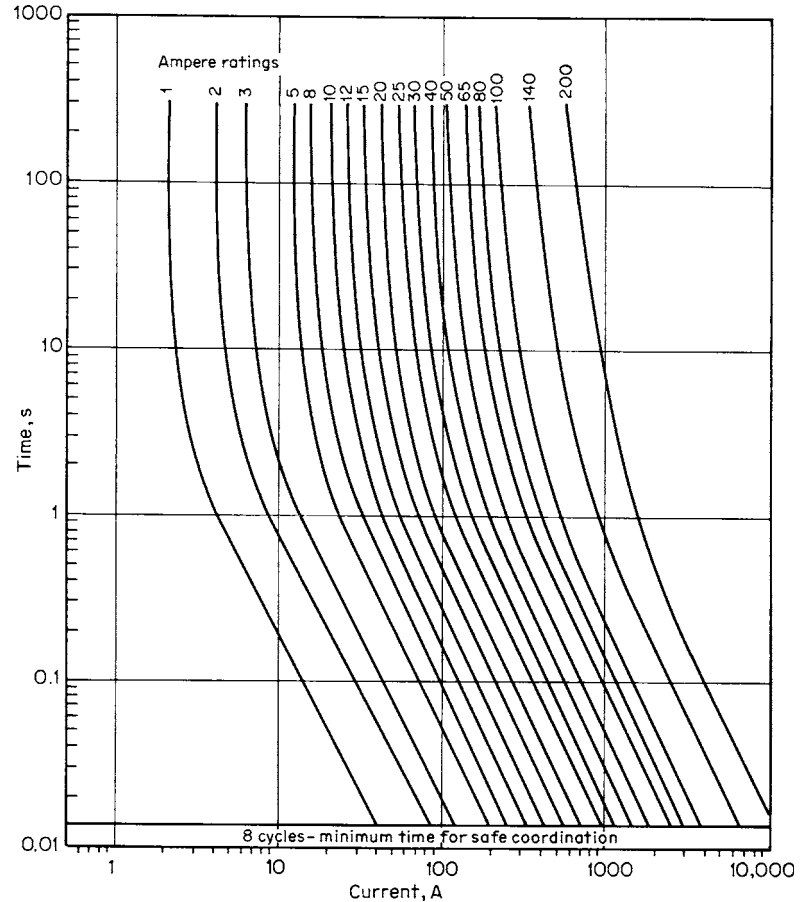


FIGURE 10-122 Minimum melting time-current characteristics of a NEMA Type K fuse. (A. B. Chance Company.)

5. *Under-oil protective link*: 4000-A asymmetric maximum interrupting current, violent in operation, low cost, contaminates insulating oil.
6. *General-purpose current-limiting fuses*: Nonviolent, current-limiting, high interrupting current (50 kA), requires coordination study, generated peak arc voltage, not affected by system transient recovery voltage, both initial purchase and replacement expensive.
7. *High-range backup current-limiting fuses*: Current-limiting, high interrupting current (50 kA), requires a low-current interrupting device in series, operates only at high currents, does not affect existing system coordination, low refusing cost on majority of outages because of only blowing expulsion link, not affected by system transient recovery voltage.
8. *Vacuum fuses*: Function with no external arcing or violence. They are nonrenewable and the associated cost is high. They have not found widespread application.
9. *SF₆ fuses*: Function with no external arcing or violence. They utilize rotating-arc technology and have a 12.5-kA interrupting current rating.

All expulsion-principle fuses depend on arc-quenching material—bone fiber, liquid solutions, or boric acid powder—to develop water vapor and/or other gases to cool the arc from the melted fuse

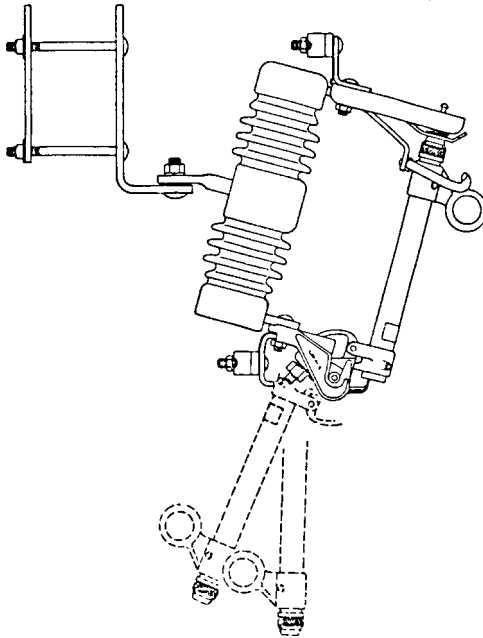


FIGURE 10-123 Open-type distribution fuse cutout.
(A. B. Chance Company.)

link. These fuses have no energy-limiting ability and require a natural current-zero crossing to successfully interrupt a short-circuit current. Figure 10-124b shows a cross section of a power-type fuse.

Current-Limiting Fuses. High-voltage current-limiting fuses for use on distribution systems have two distinct classes: (1) *general-purpose current-limiting fuses*, devices which will successfully interrupt currents which will melt the fusible element in 1 h—these are sometimes referred to as full-range fuses, but this is not an industry-accepted designation; and (2) *backup current-limiting fuses*, devices which have a definite minimum interrupting rating as specified by the manufacturer. These devices require other protective devices in electrical series to protect the backup current-limiting fuse from currents below its minimum interrupting rating. Recently, a new type of backup current-limiting fuse has entered the market. This device, which is referred to as a *fuse limiter*, combines the series fuse and the current-limiting fuse into one convenient package that handles just like a cutout. The fuse limiter is available at 15 and 25 kV, and in current ratings through 20 A. It is specifically

designed for protecting overhead distribution transformers (see Fig. 10-125).

Three important parameters should be known about high-voltage current-limiting fuses:

1. *Continuous current rating:* The maximum current that the fuse is designed to carry continuously.
2. *Peak arc voltage:* Maximum voltage generated by the current-limiting fuse. If wire-wound, the voltage value is a function of fault current. If it is a ribbon-element fuse, the voltage is a function of applied voltage across the fuse.
3. *Pt clearing:* Maximum allowed by the current-limiting fuse. This measures the energy-limiting effect of the fuse.

Care in application of current-limiting fuses according to voltage rating must be maintained. In general, these fuses should not be applied to circuits with a voltage less than 50% of the fuse-voltage rating to avoid excessive peak arc voltages.

It is equally important that fuses not be exposed to system recovery voltages in excess of their rating.

Fuses in Enclosures. High-voltage fuses may be mounted in enclosures for several applications: industrial service entrance switchgear, pad-mounted switchgear or transformers for underground circuits, or in enclosures for subsurface applications. Most fuses will require special adaptation. Power fuses are fitted with a muffler to reduce the intensity of the exhaust gases when used in enclosures. Current-limiting fuses are supplied with special seals to prevent the ingress of fluid when applied under oil such as in transformers. Fuse cutouts are not recommended for use in enclosures or vaults.

Derating of fuses in enclosures may have to be considered because of restricted heat transfer. Consult the manufacturer.

Electronically Controlled Protective Devices. Electronically controlled protective devices offer greater flexibility and accuracy through the use of state-of-the-art electronics. An electronic power

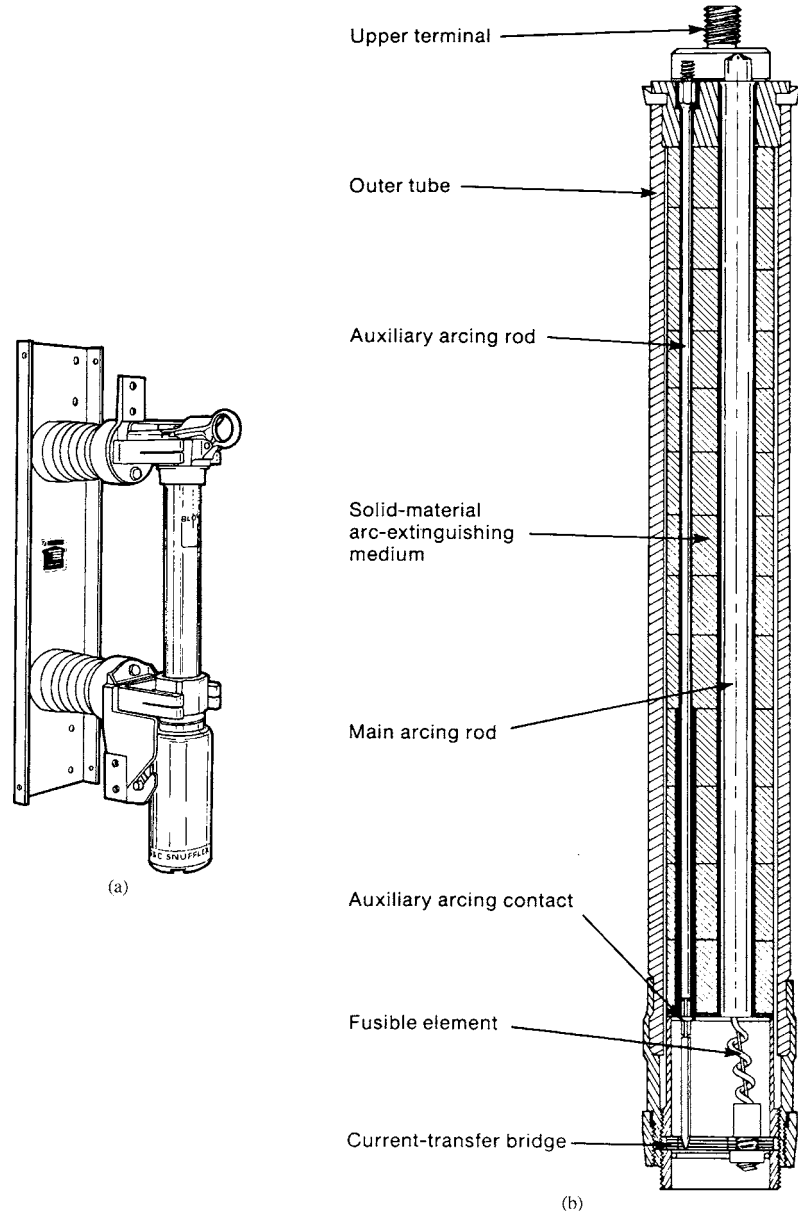


FIGURE 10-124 (a) Indoor-type power fuse; (b) cross-sectional view of power-fuse refill unit. (S&C Electric Company.)

fuse and an electronic sectionalizer for use at distribution voltage levels are two examples of this technology.

The electronic power fuse utilizes an electronic control module to provide current sensing, time-current characteristics, and control power for the fuse. High-speed interruption of fault currents to 40,000 A is provided by an interrupting module. The devices are completely self-contained (nonventing) and

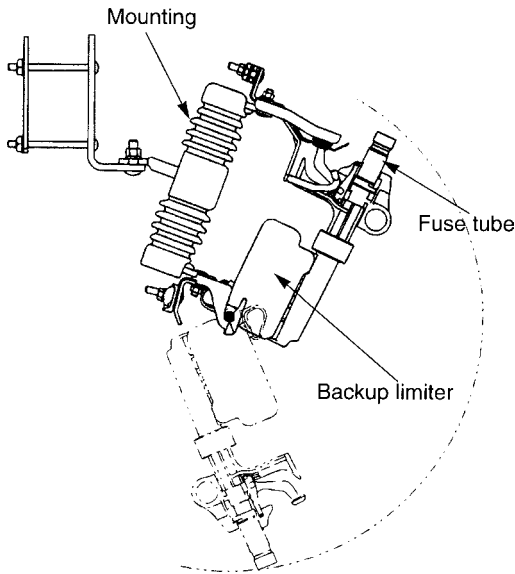


FIGURE 10-125 Fuse limiter. (*S&C Electric Company.*)

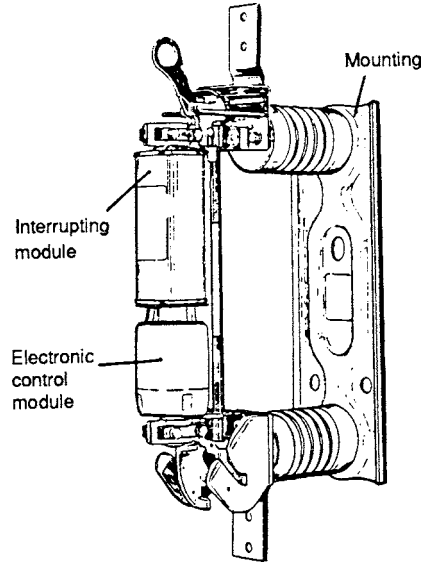


FIGURE 10-126 Electronic power fuse. (*S&C Electric Company.*)

require no external power source. These power fuses are used in metal-enclosed switchgear, pad-mounted switchgear, and metal-enclosed fuse gear. They are available to 600 A continuous current and 4.16 through 25 kV. Three families of time-current characteristics are available. Figure 10-126 shows an electronic power fuse.

The electronic sectionalizer consists of an electronic module which fits into the mounting of a standard open-type cutout. The sectionalizer counts the number of fault current pulses allowed by an upstream recloser and operates to an open position during the recloser's open time. The sectionalizer has no time-current characteristics. It is generally used to replace a fuse at the distribution lateral where fuse coordination is difficult or impossible. Sectionalizers have no fault-interrupting capability and must be used in conjunction with an upstream recloser. Sectionalizers are available in continuous current ratings to 200 A; count settings of 1, 2, or 3; and distribution voltage ratings from 15 to 38 kV. The electronic modules require no external power source. An electronic sectionalizer is shown in Fig. 10-127.

10.6.2 Switches

Disconnecting switches are used primarily for isolation of equipment such as buses or other live apparatus. They are used for sectionalizing electric circuits such as buses or lateral circuits or even portions of main feeders for special purposes such as testing and maintenance. Standards pertaining to disconnect switches are listed in Table 10-16. Generally, these devices are not rated to break load current except when equipped with specific auxiliary devices. Interruption of load currents, magnetizing currents, or capacitive currents without other aiding devices may not be successful. While not recommended, disconnect switches without loadbreak capability have been used to interrupt limited values of load, charging, and magnetizing current. Their performance depends not only on the magnitude of the current but also on the speed of operation, wind direction, velocity, and clearance to other energized or grounded components. The principal concern is that the arc which is created may establish a high-current fault. Arc reach may approach tens of feet or more depending upon system voltage and the current being interrupted. However, these switches must be designed to carry

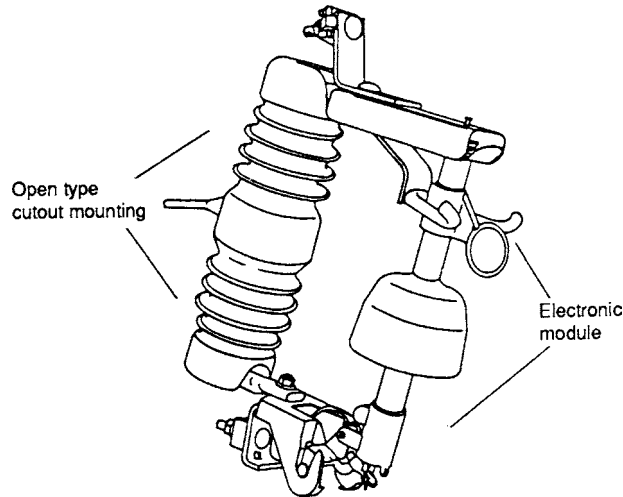


FIGURE 10-127 Electronic sectionalizer. (*S&C Electric Company.*)

expected load currents and remain closed for momentary current flow such as fault currents. Fault currents in excess of a specific rating may cause the switch to be blown open by the magnetic forces due to the short-circuit current.

There are three classes of disconnect switches:

1. Station
2. Transmission
3. Distribution

Switches can be further categorized as gang- or hookstick-operated and loadbreak or nonload-break types.

The basic insulation level (BIL) of station-class equipment is normally higher than for transmission or distribution equipment. Station equipment ranges from 2.4 to 765 kV at present. Disconnect switches rated up through 3000 A are available. Manual or automatic switching can be provided.

The design of disconnecting switches demands considerable attention to the contact surfaces. Consideration must be given to the rigors of extreme environments.

High-pressure contacts are generally the form used to provide the current transfer. Current densities of 100,000 A/in² are not uncommon when using silver for contact points. Contact pressures as high as 500,000 lb/in² ensure that good cleaning action is achieved and keeps the current transfer points free from contamination.

Transmission disconnecting switches are generally used as load-management tools. Increasing needs for transmission lines and decreasing availability of right-of-way makes automatic switching of transmission load desirable.

Load management is achieved during “dead time” by switching the proper disconnects automatically through sensing loss of voltage. These systems are available through 161 kV, 1200 A.

The objective of load management is to minimize outage time and allow for more efficient utilization of substation capacity at the distribution level. There is a growing interest in automating distribution class switches to achieve load-management objectives.

TABLE 10-16 Standards Related to Disconnect Switches

Ratings and Application Guide	ANSI C37.32
Rated Control Voltages	ANSI C37.33
Test Code	ANSI C37.34
Operation and Maintenance	ANSI C37.35
Loading Guide	ANSI C37.37

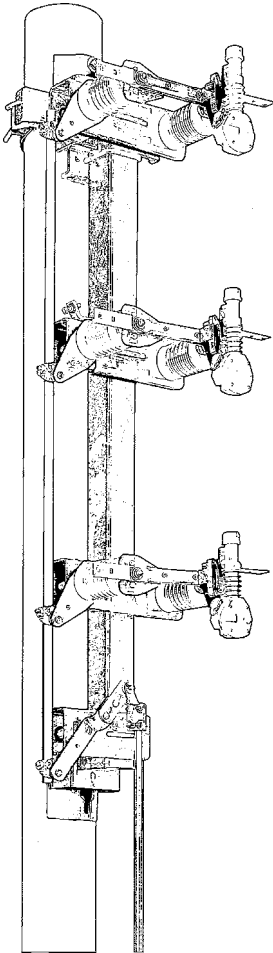


FIGURE 10-128 Gang-operated, phase-over, distribution load-break switch. (S&C Electric Company.)

Distribution disconnecting switches are becoming the method of providing for both single- and 3-phase sectionalizing. As distribution voltage grows to higher levels, the utility must provide more sectionalizing or switching capability or suffer large and longer outages during faults. Hence, at 34.5 kV one may find some switching capability every 2000 to 3000 ft of overhead conductor. Figure 10-128 shows a typical gang-operated distribution loadbreak switch.

Single-phase disconnect switching with load-interrupter capability can be applied where ferroresonance is not a problem. This type of switching is found on single-phase circuits. Single-phase switching of a heavily loaded 3-phase circuit is not desirable.

Gang-operated switches with loadbreak capability interrupt these loads without concern for ferroresonance problems. In application, these 3-phase switches can be mounted in either horizontal or vertical configurations. To ensure proper operation, the mounting should be as rigid as possible. Care must be exercised in proper alignment of blades and clips. Attention to these matters allows proper operation without overstressing porcelain insulators or distortion of contact surfaces and operational handles.

Load-Interrupter Devices. Load-interrupter devices, when combined with disconnecting switches, provide the desired capability of switching load currents without circuit breakers. Generally, these interrupters are auxiliary devices and are not continuous-duty in terms of carrying load. This load interruption can be achieved by

1. Insertion of a resistor in the circuit following opening of the main switch contact and interruption of the current drawn between arcing horns in the air.
2. Use of a blast of air or other gas to effectively lengthen the arc resulting from the main contacts opening.
3. Use of an interrupter paralleling the main contacts just prior to opening and interrupting in this auxiliary chamber after the main contacts open. This is typically accomplished with an expulsion-type device or vacuum switch.

Figure 10-129 shows an expulsion-type load interrupter used on distribution disconnecting switches to assist in interrupting load current.

Switches for Underground Circuits. The continuing trend toward underground distribution circuits increases the need for pad-mounted switchgear. These are available in both live- and dead-front configurations, with the latter growing in popularity.

Live-front switchgear is typically air-insulated and utilizes in-air switches for loadbreak operation and power fuses for fault interruption. All components are directly accessible and operable.

Dead-front switchgear is typically air-, oil-, or gas-insulated. Air-insulated dead-front switchgear is similar to live-front switchgear except that components are isolated within grounded compartments and are not accessible when energized.

Oil-insulated dead-front switchgear typically uses in-oil switches or vacuum interrupters for loadbreak operation and current-limiting fuses or vacuum interrupters for fault interruption. These have the advantage of being more compact than air-insulated units. The disadvantage is that the oil insulation can become contaminated following in-oil arc interruption or from external contaminants. SF_6 -insulated switchgear uses components similar to those used in oil-insulated switchgear. Contamination of SF_6 is less of a concern, although SF_6 -insulated gear must be more carefully designed and constructed to ensure gas integrity.

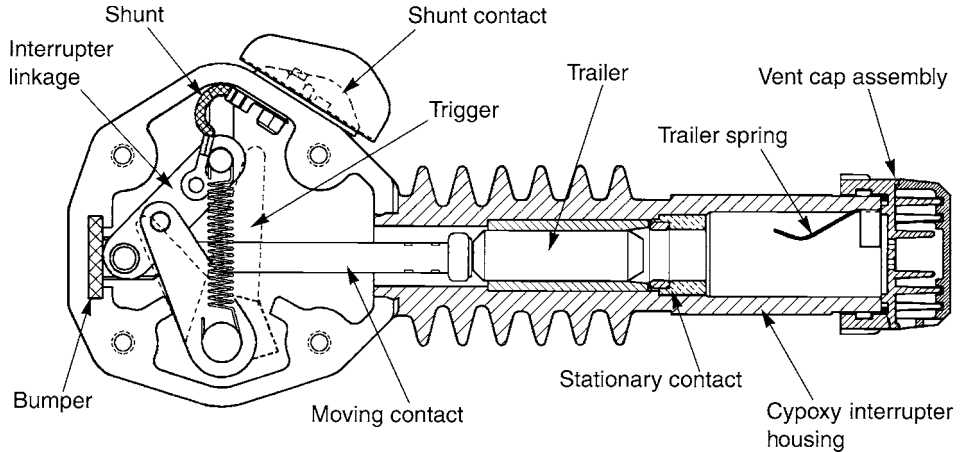


FIGURE 10-129 Load interrupter, expulsion type, used in distribution systems. (S&C Electric Company.)

Dead-front designs generally provide increased isolation from energized components, but at the expense of operating simplicity and visual confirmation. External connections are made by means of separable insulated connectors. These connectors generally must be removed to provide a visible break when working on cable or equipment. Some more recent dead-front designs allow visual confirmation of internal visible breaks on both switches and fault interrupters, and some provide integral grounding of cables. This eliminates the need to move elbows and provides isolation from energized components, while also offering the visual confirmation provided in live-front switchgear.

In addition, recent designs have become available either with provisions for motor operation or fully integrated with motor operation and controls for use with SCADA systems.

Oil-insulated and SF_6 -insulated switchgear can also be submersible and thus used in subsurface applications where space is at a premium or aesthetics are critical, such as in metropolitan areas. Refer to ANSI C37.72 for standards governing dead-front pad-mounted switchgear, and ANSI/IEEE C37.71 for subsurface load-interrupting switches.

10.7 CIRCUIT SWITCHERS

BY JON HILGENKAMP

Circuit switchers are mechanical switching devices suitable for frequent operation; not necessarily capable of high-speed reclosing; capable of making, carrying, and breaking currents under normal circuit conditions; capable of making, and carrying for a specified time, currents under specified abnormal conditions; and capable of breaking currents under certain other specified abnormal circuit conditions. They may include an integral isolating device. Circuit switchers available today use SF_6 as an interrupting medium and may be equipped with a trip device connected to a relay to open the circuit switcher automatically under specified abnormal conditions, such as overcurrent or faults.

A circuit switcher, like a circuit breaker, must carry normal load currents within a specified temperature range to prevent damage to key components such as contacts, linkage, terminals, and isolating device parts. Principal designating parameters of a circuit switcher are maximum operating voltage, BIL, rated load current, interrupting current, whether an isolator is required, whether a trip device is required, and whether manual or motorized operation is required.

A circuit switcher essentially combines the functions of a circuit breaker (without reclosing capability) and a disconnecting switch (by providing visible isolation, but not necessarily meeting the

safety requirements of all users). A circuit switcher provides a cost-effective alternative means of transformer protection and switching, line and loop switching, capacitor or reactor switching, and load management, with protection in most instances.

Evolution of the circuit switcher concept provides a more in-depth understanding of its application versatility and its limitations.

10.7.1 History of Circuit-Switcher Development

After World War II, the drive to electrify the remaining rural and sparsely populated areas of the United States was renewed. Providing fully rated circuit breakers for switching loaded circuits was frequently beyond budget limitations. This created a need for new transmission and subtransmission voltage circuit-switching devices. One such device could be described as a load interrupter. It appeared in a wide variety of forms. Most were attachments to disconnect switches.

Initially, most of these devices used low-volume oil as an interrupting medium. Ablative gas-generating devices and later vacuum displaced oil. With rare exceptions, these devices had deficiencies.

In the mid-1950s, SF_6 was first employed as an interrupting medium. The application was an interrupter attachment for disconnect switches.

Whereas ablative devices and vacuum bottles are limited to approximately 30-kV recovery voltage per gap, this single-gap SF_6 device was readily applied on 138-kV systems for up to 600 A loadswitching. Most of these vacuum, ablative, and SF_6 devices were shunted into the circuit during the disconnect switch opening process. As the 1960s approached, the circuit switcher was born. It appeared as an in-line device. While the first version employed a number of ablative devices in series, it soon evolved into the use of SF_6 as a medium. Because of the unfavorable experience with the earlier devices, the general acceptance of the circuit switcher took much effort and considerable time. A typical installation is shown in Fig. 10-130.

Applications for circuit switchers have been primarily for transformer protection. The circuit switcher provides load-switching capability and mainly protection for faults that originate on the secondary side of the substation transformer. The zone of protection for circuit switchers in this

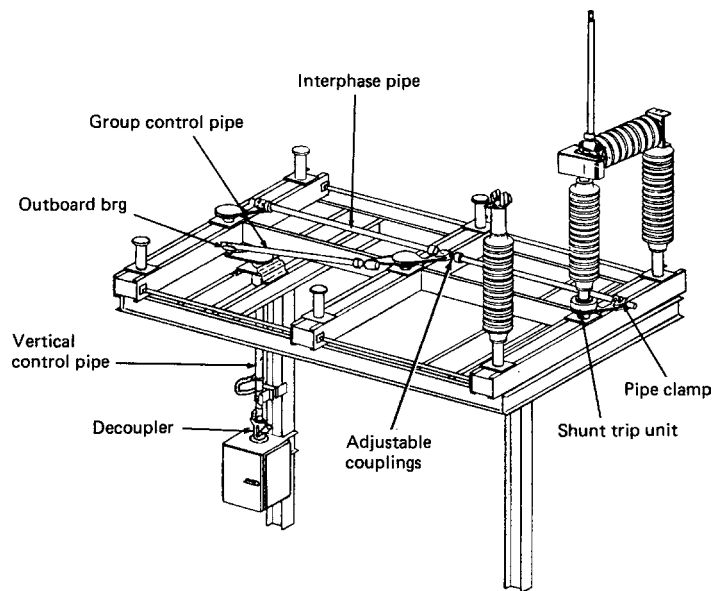


FIGURE 10-130 Schematic of typical 3-pole arrangement. Two poles have been deleted to clarify mechanical drive-train arrangement.

location is typically from the current transformers inside the transformer on the high-voltage bushings to the secondary feeder breakers. There is generally shorter strike distance on the secondary bus and more exposure to flashover from wildlife and other causes. Therefore, circuit switchers are specifically tested to interrupt the higher transient recovery voltages (TRVs) associated with faults initiated on the secondary of the transformer and cleared by the high-side protective device. For application where the available high-side short-circuit current exceeds the device's capability, blocking relays can be used. However, in most applications this is not necessary.

10.7.2 General Construction

Live-tank SF₆ gas puffer-type interrupters are utilized by most circuit switchers today. In the closed position, the contacts are surrounded by a flow guide and piston assembly which is ready to mechanically generate a "puff" of SF₆ to cool and deionize the arc that is established prior to circuit interruption. The moving cylinder attached to the contact assembly is driven by the main opening spring, causing the gas to be pressurized by the stationary piston. The stationary contact "follows" the moving contact as the piston assembly achieves the prepressurized gas condition. When the contacts (which are hollow tubes) part, an arc is established and the gas flow divides into two parts and flows down the stationary and moving contact tubes. The alternating nature of the arc current waveform results in two current zeros every cycle. As long as the arc is sufficiently "hot" or conductive through the SF₆ dielectric medium, the current will reestablish. At the first current zero where the SF₆ density is sufficient to stop the arc from reestablishing itself and to provide necessary dielectric strength, the arc is interrupted. This entire process from trip signal initiation to current interruption requires from 3 to 8 cycles or 50 to 133 ms in modern circuit switchers.

Figure 10-131 illustrates a typical "blade-disconnect model" circuit switcher with the interrupter and blade connected in series. For opening, the trip device, called a "shunt trip," receives a trip signal when the relay system detects an abnormal condition within the specified range or when the operator desires a high-speed circuit opening. By discharging its operating spring, the shunt trip rotates the insulator above it at high speed, thus tripping and discharging the opening spring in the driver mechanism. This actuates the interrupter to open the circuit. If the insulator above the shunt trip continues to rotate, by motor or manual actuation of the drivetrain controls, the blade opens to achieve visible isolation. The blade-hinge mechanism is actuated directly by the rotating insulator through the driver mechanism. Continued rotation of the insulator after the blade is open will "toggle" the drivetrain controls to lock the blade in its open position.

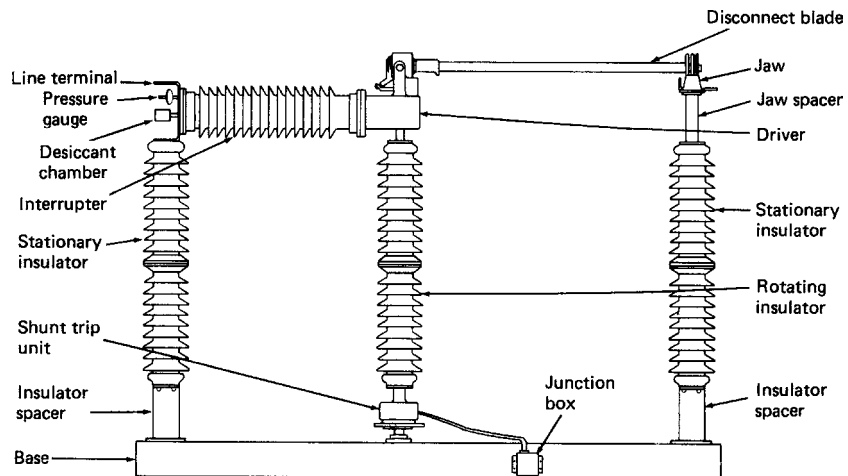


FIGURE 10-131 Single pole of blade-type circuit switcher.

For closing, the reverse rotation of the insulator first releases drivetrain toggle and allows the blade to begin closing. The shunt-trip units have already recharged during the opening operation. As the blade closes, the closing springs are charged in the driver. The last few degrees of closing rotation lock the blade in position and release the closing springs in the driver, thus closing the interrupter. The opening springs are charged as the closing springs discharge. If the unit has closed into a circuit condition that provides a trip signal to the shunt trip units, the opening process may immediately proceed since all springs are charged and all controls are ready.

The closing operation may be achieved in other designs by closing the interrupter during the opening stroke of the blade. When a close operation is called for, all that is necessary is to close the blade, because the interrupter is already closed. Because of the arc established in air for this type of closing, high-speed operation of the blade is necessary to minimize damage to contacts and prevent flashovers. Both methods of closing are proven over many years of field use.

Bladeless circuit switchers operate exactly the same as blade models, except that on opening, the insulator rotation is used only for driver and interrupter actuation. Models that depend on high-speed blade operation for closing are available in bladeless nondisconnect configuration, but circuit closing must be accomplished by other means.

For models without shunt trip, opening is accomplished by rotating the insulator to the point where the driver opening spring would normally be tripped by the shunt trip's rotation. This configuration is used where protection duty is not a function of the circuit switcher.

Transformer Protective Devices. Recently, a new transformer protective device has entered the market specifically for application on the high-side of substation transformers from 69 to 138 kV. These devices offer a 3-cycle 31,500 A interrupting rating with electronically linked pole units. They have been tested for interrupting the high TRVs from secondary-side faults and provide an economical alternative to other protective devices. They are supplied in conjunction with a separate or integrated disconnecting device on the high-voltage side of the protective device. Figure 10-132 shows a typical substation transformer protective device.



FIGURE 10-132 Substation transformer protective device. (*S&C Electric Company.*)

10.7.3 Ratings

Short-Circuit Current. Circuit switchers are “specific-duty” or “medium-fault” interrupting devices and generally fulfill a requirement between high-power fuses and circuit breakers in a transmission or distribution system. Circuit-switcher designs to date do not encompass instantaneous reclosing capability since their most common application of transformer protection precludes this requirement.

Typical short-circuit current ratings are from 4 to 40 kA on a symmetric current basis, depending on type of interrupting duty and voltage rating. The symmetric current is the highest value of the ac component in rms amperes measured at the instant of contact part.

When interruption occurs, a TRV is imposed in microseconds across the interrupting device as a result of system adjustments to the new state before a steady-state condition is achieved known as the normal-frequency recovery voltage. TRV attempts to reestablish the arc by either thermal reignitions or dielectric breakdown of the interrupting gap. Refer to ANSI C37.04 and C37.06 for TRV definitions and ratings. The TRV seen by the highside interrupting device after clearing a fault that initiated on the secondary of the transformer is high because of the characteristics of transformer.

Continuous Current. A continuous current rating is the designated limit of current in rms amperes that can be carried continuously under usual service conditions and in an ambient temperature not in excess of 40°C without exceeding temperature limits assigned to the various materials comprising the current-carrying parts or that are in contact with these parts. For further information refer to ANSI C37.04, C37.30, and IEC 694.

Circuit-switcher continuous current ratings are 1200, 1600, and 2000 A.

Short-Time Current. This is a dual rating to verify the capability of the circuit switcher to carry abnormally high currents in the closed position for short periods of time

1. Rated momentary current is the total current in asymmetric rms amperes (ac and dc components) carried for 10 cycles on a 60-Hz basis. These ratings can approach 50 times the continuous current ratings and assure the device will withstand the high electromagnetic forces from initial transient conditions of a short circuit tending to bring about mechanical damage or contact separation.
2. Rated 3-s current is 62.5% of the rated momentary current and verifies that the current-carrying parts will withstand the heating effect without excessive annealing or contact welding. Common circuit switcher momentary ratings are 61, 70, and 80 kA.

Close-and-Latch Current. For those circuit switchers that make the circuit in the interrupting device, a close-and-latch rating is required as is a close rating for the type that closes the circuit on a disconnect switch blade. This rating verifies the capability of the contact structure and operating mechanism to withstand the forces developed by closing in on a fault. Close-and-latch ratings are 30 and 40 kA. Limited-duty close ratings for the blade type are of the same magnitudes.

Rated Voltage. Rated voltages for circuit switchers are generally stated in terms of maximum system design voltages that indicate the upper limit at which the device is designed to operate. Circuit switchers are most commonly applied at 72.5 through 242 kV but are also available for special applications at 362 kV.

In order to provide safe insulation levels to ground and across the device when in the open position, the circuit switcher must withstand certain specified magnitudes and waveshapes of test voltages without flashover or puncture of any of its insulation systems. This is the rated dielectric strength and consists of

1. One-minute dry and 10-s wet low-frequency (60-Hz) withstand voltage.
2. Dry lightning-impulse ($1.2 \times 50 \mu\text{s}$ waveshape) withstand voltage. It is the positive-polarity withstand level that is the basic-insulation-level rating (BIL in kilovolts).
3. Dry and wet switching-impulse ($250 \times 2500 \mu\text{s}$) withstand voltage. This rating applies only at 362 kV and above.
4. Dry chopped-wave impulse withstand voltage. The requirement for this rating has yet to be determined for a circuit switcher but is a standard rating for a circuit breaker. If applicable, this rating would apply to a bladeless model circuit switcher having graded gaps in series per pole.

Interrupting Time. The rated interrupting time is the maximum permissible interval between energizing the shunt trip coils at rated control voltage and the interruption of the main circuit in all poles when interrupting a current within the required interrupting capabilities. This interrupting time may be modified under certain asymmetrical current conditions as detailed in ANSI C37.04. Circuit switchers are available from 3- to 8-cycle interrupting times.

Duty Cycle. Operating duty is the short-circuit current to be interrupted, closed upon, etc. The duty cycle is a stated sequence of closing and opening operations. Various types of circuit switchers will have different duty cycles. An example is O-17s-CO where the first operation is an open followed by 17 s to permit the operating mechanism and blade to recycle in order to perform the close-open cycle.

Corona-RIV. A corona-free rating is commonly established to prevent radio and television interference. This is referred to as the radio influence voltage (RIV) and should be less than 500 μV as determined by a test circuit per NEMA Publication No. 107. As a general rule, a circuit switcher that produces no visible corona under dark conditions at 105% of rated voltage will have a negligible RIV level.

10.7.4 Selection and Application

The versatility of circuit switchers and related circuit-interrupting devices requires careful selection of the ratings, components, and accessories to be specified for a given protection and/or switching duty. The following criteria must be considered:

1. System data
 - a. Nominal service voltage
 - b. Maximum continuous current
 - c. Through-fault current withstand
 - d. TBasic impulse (insulation) level
2. Circuit-protection duty
 - a. Present and future available fault currents
 - b. Length of overhead lines or underground cables
 - c. Transformer ratings, impedance, and connections
 - d. Transient recovery voltage
 - e. Interrupting time, maximum
3. Switching duty
 - a. Inductive currents (unloaded transformers)
 - b. Small capacitive currents (unloaded lines and cables)
 - c. Inductive/capacitive currents (choke coils, capacitors, grounded or ungrounded)
 - d. Closing on fault
 - e. Closing of long lines

Approximately 80% of all circuit switchers are applied on the primary or high-voltage side of a transformer for switching and fault-protection duty. By means of protective relaying, faults which occur within the protection zone of the transformer can be detected to bring about tripping of the primary-side circuit switcher. Should the fault occur on the secondary side, which is most frequently the case, the magnitude of fault current at the circuit-switcher location is limited by the transformer impedance and is less than the available primary-fault current. Hence, the use of the term “inherent secondary-fault current,” and for some circuit switchers, a dual short-circuit current rating for primary or secondary faults.

Associated with these reflected secondary faults are the inherent capacitance and inductance of the transformer windings, which generally produce higher TRVs than is the case with a primary fault. These higher TRVs can increase the difficulty of the interruption process, while conversely, the impedance-limited fault current is easier to interrupt. Circuit switchers are tested for this condition as defined in the nearly completed ANSI C37.016 which is the new standard for circuit switchers. This

test standard defines secondary fault test with a TRV that is more severe than the circuit breaker test standard. Therefore, the circuit switchers demonstrate interrupting capability for this specific duty.

Primary-fault currents in excess of the switcher rating can often be cleared by source-side circuit breakers having interrupting times shorter than those of a circuit switcher. It is also common to block tripping of the circuit switcher when the fault current is in excess of its rating and pass this duty on to the source-side breaker.

Circuit switchers and interrupters are generally available in mounting arrangements similar to isolating air-disconnect switches. Since they are not freestanding, their application and that of the supporting structure design and/or optional freestanding pedestal is influenced by phase spacings desired, terminal height, altitude, atmospheric elements, seismic conditions, and wind, ice, and terminal pad loadings.

The phase spacing recommended in the ANSI C37.32 differentiates between the minimums for vertical-break disconnect switches (also applying to bus supports) and the increased spacings required for horn gap switches (switching devices utilizing arcing in air as an operating mode). From a safety viewpoint, it is important to consider the method of operation in addition to the duty applications of the particular device as a determination in selecting the phase spacing.

Elevation of the installation site, in addition to the temperature, humidity, and air-contamination characteristics, significantly affects the dielectric strength and coordination of these circuit-interrupting devices. The guidelines established in ANSI C37.30 for site elevations coupled with a further analysis of these other factors may dictate the use of higher-voltage-rated units or extra-leakage-distance porcelain standoff insulators.

Seismic, wind, ice, and terminal pad loadings must also be considered in the design of the supporting structure.

Testing. Industry standards specifically for circuit switchers have yet to be fully implemented. There is a draft standard, ANSI C37.016, which is close to being adopted. Accordingly, up to this point applicable sections of existing standards for circuit breakers and disconnect switches have been used as a guide in establishing definitions, ratings, capabilities, and test procedures for circuit switchers (see ANSI C37.09 and C37.34). In addition, specific testing for secondary fault currents and the associated higher TRVs has been completed by some circuit switcher manufacturers.

Tests can be considered to consist of four different groupings:

1. Type or design tests are for the purpose of proving the capability of the switcher to meet the specified ratings.
2. Reliability tests are part of a quality assurance program to demonstrate that the circuit-switcher design has achieved a specified mechanical reliability. They consist of growth or prototype tests to improve on the established design reliability, demonstration, or pilot run tests to assure the reliability requirements have been met, and acceptance or production tests to verify that production units comply with the demonstrated design reliability.
3. Routine or production tests are done to ensure that the production is in accordance with established procedures. This includes testing of individual components and subassemblies.
4. Installation testing to assure that the circuit switcher will perform its intended function in the system.

Accessories and Maintenance. As discussed in a preceding section, circuit-switcher manufacturers offer optional freestanding support pedestals in addition to many other accessories, some of which

10.8 AUTOMATED FEEDER SWITCHING SYSTEMS

The method known as SCADA has long been used to control transmission systems, providing the operational flexibility and speed required for efficient and reliable performance. The use of SCADA in the distribution system is becoming increasingly important as utilities move into a deregulated,

competitive environment. The acronym *SCADA* is being replaced by the generic term *distribution automation* (DA), which incorporates the principle of computers operating switching and other control devices automatically in response to preprogrammed events in the system. Automated switching of distribution feeder circuits provides significant improvements in reliability, enhances operational flexibility, and increases productivity of both utility personnel and distribution lines.

Automated feeder switching systems utilize controls, sophisticated algorithms, and data communications to go beyond the reliability benefits of more traditional reclosers and automatic sectionalizers. An automated switching system can be programmed to not only reduce outage times, but do so without subjecting unfaulted circuits to “bumps” caused by intentional closing into faults required by fault-detection or troubleshooting schemes. Further, an integrated fault-isolation and restoration system can incorporate real-time evaluation of prefault loads into the algorithm to prevent overloading of a backup circuit when transferring load from a faulted circuit. This allows the utility planner more flexibility in circuit design by increasing the amount of load that can normally be carried by a given circuit.

Such systems, with current and voltage monitoring, also provide the utility with a convenient way to monitor distribution feeder circuits, thus enabling the utility to take immediate action in the event of current or voltage excursions exceeding normal operating limits. This, in turn, results in improved power quality and service for the customer.

Automated feeder switching systems can also provide the means to optimize feeder and substation loading by enabling the shifting of load from one feeder to another in a very short time frame. This same capability can yield hard-dollar cost savings associated with deferment of capital projects when coupled with planning practices that take advantage of the new technologies.

With the increasing power of computers and improving communications, it is certain that automated feeder switching systems will provide benefits that have yet to be considered in the electric utility industry.

Examples of Automated Feeder Switching Systems. A large investor-owned electric utility in New York needed to dramatically improve reliability in response to a challenge from the New York public utility commission. After analyzing its system as well as the nature and locations of faults, it was decided that an automated feeder switching system would provide the quickest route to needed improvements in electric service reliability.

A typical MES feeder “loop” is shown in Fig. 10-133. It consists of two circuits joined by a normally open tie switch. In turn, each feeder circuit will have a normally closed automated switch installed at the electrical half-way point on the circuit. All switches are equipped with voltage and current monitoring as well as communication and control units (CCUs) housing the switch controls,

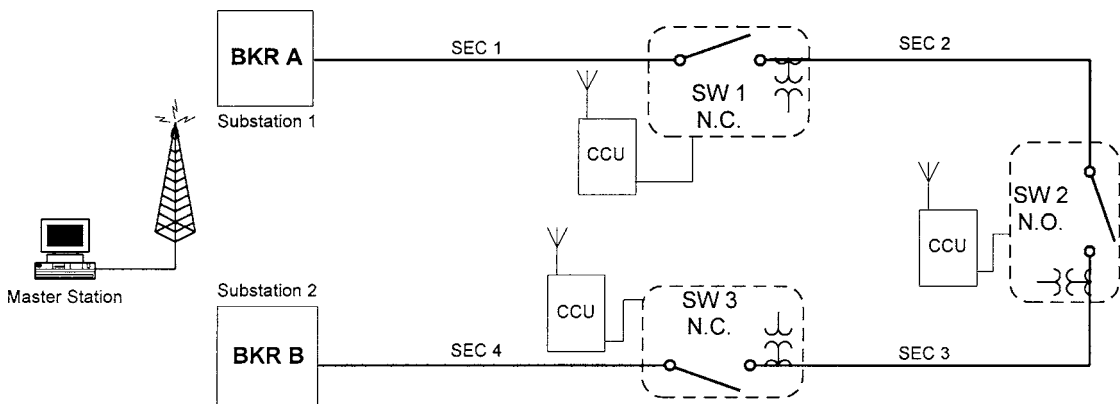


FIGURE 10-133 Typical automated feeder circuit loop.

power supplies, remote-terminal units (RTUs) and radios for establishing communication with the master station.

Faults occurring in Sec. 2 will result in a trip of substation breaker BKR A. The control at switch SW1 will sense the passage of fault current and the subsequent loss of voltage precipitated by the opening of BKR A. A sectionalizing algorithm will initiate and open the switch after a predetermined time delay set to coordinate with the recloser interval of BKR A. The station breaker is reclosed to determine if the fault condition is temporary or permanent. A typical reclosing breaker may reclose up to 3 times on some systems. Once SW1 is open and the fault is isolated, BKR A will reclose, restoring service to the customers in Sec. 1. At this point, the crew can proceed directly to SW1 and commence the search for the fault from there, further reducing the amount of time for fault location.

Faults occurring in Section 1 will result in a lockout of substation BKR A. At this point, SW1 will see a loss of voltage and transmit an alarm to the master station. The master will then interrogate SW1 and find that it saw loss of voltage, but no overcurrent. This condition indicates a section 1 fault. The master station will then initiate the section 1 fault algorithm and interrogate SW1 to determine the load in section 2 just prior to the fault. The master then interrogates SW3 for load information. If the addition of section 2 load to the current load on section 3 will not result in an overload condition, then the master station will instruct SW2 to close, restoring service to section 2.

The MES system can be operated in three modes. The first is traditional SCADA, where the dispatcher must identify and analyze circuit conditions before deciding on restoration procedures, which must then be sent to the field devices individually. In the second mode, the master station computer will identify and analyze the circuit condition and make an operational recommendation to the dispatcher, who can then choose to accept the recommendation and execute a simple acknowledge command which will automatically issue appropriate commands to field devices. The third mode identifies and analyzes circuit conditions and automatically issues commands to field devices to isolate faulted sections and restore service to unfaulted sections. It should be noted that the system can utilize up to seven switching devices on a given circuit loop similar to that shown in Fig. 10-133. The figure was simplified for clarity in this example.

A large metropolitan utility serving customers in and around Chicago wanted to improve electric service. However, they did not have a SCADA master station at the beginning of the project and needed a way to improve service without installing one. In this case, the utility installed a system which utilizes distributed intelligence in the switch controllers to do all analysis as well as fault isolation and circuit restoration. Such a system operates in much the same way as described in the example above. The key difference is that this system does not utilize the first two modes of operation: traditional SCADA and suggesting operational recommendations. The advantage is the ability to install the system without the need for a communications network or SCADA master station. This system does its work automatically without human intervention—or the need for a communication system. It should be noted that the system can be easily disabled in the field for line work if desired and can be upgraded to work with a master control station.

10.8.1 Automated Switches

A key part of an automated feeder switching system is the automated switch. The term “automated” in this context means the switch is designed for use on an automated or SCADA system. In order to be automated, existing switches may be retrofitted with motor operators, current and voltage sensors, RTUs and communication devices to allow the remote operation necessary to realize the benefits available with automated feeder switching systems. However, switches designed for occasional, manual operation may not be entirely suitable for operation on an automated distribution circuit feeder. Manual switches are typically not designed to be operated the hundreds of times required by a fully automated system over the life of a typical switch. Nor are they ordinarily designed for duty-cycle fault-closing to allow the system operator to inadvertently close into a fault from the SCADA master station—and still leave the switch in an operable condition.

More recently, switches designed specifically for automation have appeared in the market (Fig. 10-134). Such switches incorporate design features that make them particularly applicable for use in an automated feeder switching system:

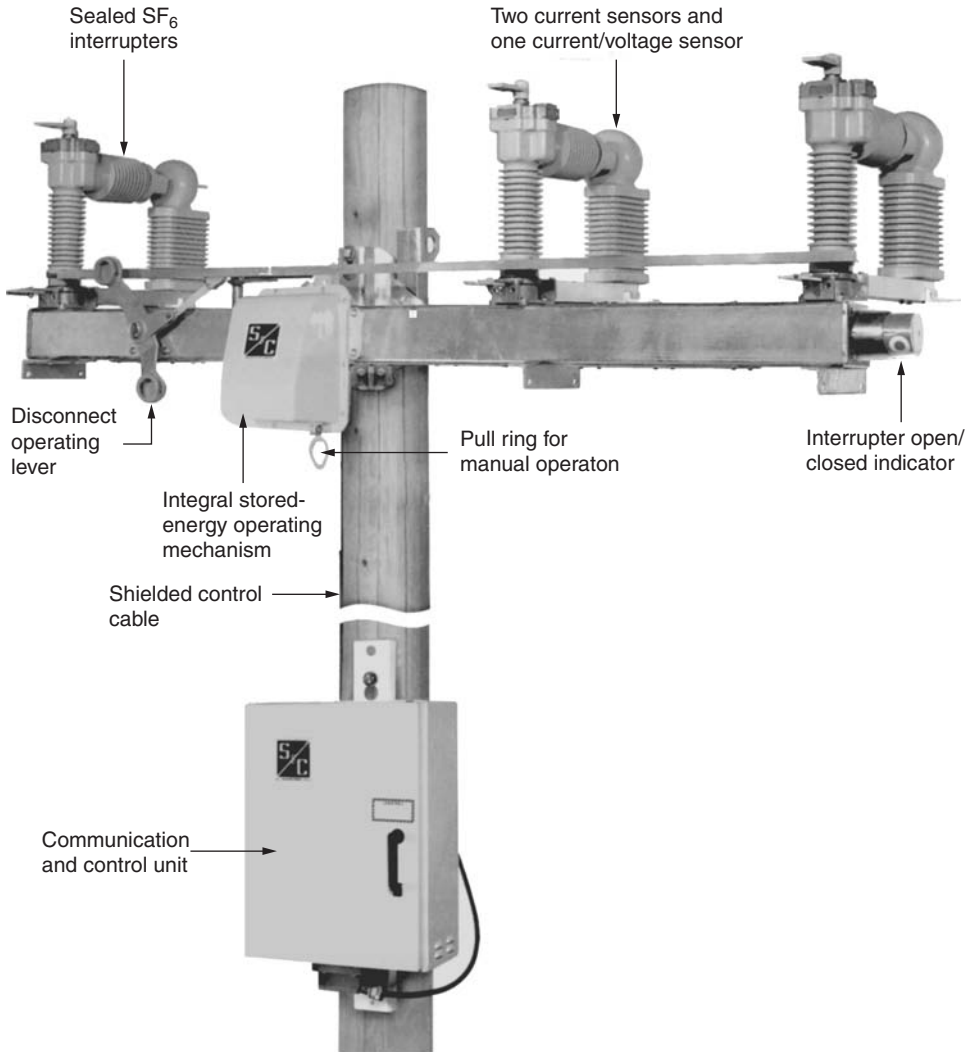


FIGURE 10-134 Scada-Mate switching system. (S&C Electric Company.)

1. *Duty-cycle fault-closing* allows the switch to be closed into a typical fault several times before experiencing damage severe enough to render the switch inoperable.
2. *Integrated voltage and current sensors* provide the ability to monitor voltages, currents, and loads that are in turn used as inputs to algorithms to effect automated switching for fault isolation and restoration and for shifting loads for circuit optimization.
3. *Integrated operating mechanisms* enable the switches to be operated remotely via computer commands. Integration with the switch ensures optimum operation without the need for cumbersome ground-to-switch linkages.
4. *Integrated load interrupters* should be designed to allow operation under any weather conditions since it will not be possible to visibly inspect the switch for ice or other problems prior to operation.

5. *Integrated control power sources* eliminate the need to rely on locally available control power sources—or to install such power sources.
6. *Integrated visible air-gap isolation* provides the visible air gap when needed for certain types of line work.

In addition, an associated control package should include switch-operating controls, a local/remote switch, backup power for dead-line SCADA operation, a remote-terminal unit, and data-communication devices. The entire package should be assembled and tested for proper operation by a single supplier to eliminate the need for the utility to perform the integration. The control box should be separately located from the switch to allow access by technicians who are not qualified in high-voltage operations. In underground switchgear applications, the control should be isolated from the high-voltage compartments of the switchgear.

